Electric Power in Canada 1984

Canada

Cover Revelstoke Hydro Electric Project on the Columbia River BC

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British Columbia Hydro

Electric Power in Canada 1984

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THE ELECTRIC POWER INDUSTRY IN CANADA

Industry Structure

Electrical energy in Canada is supplied by Crown corporations, investor-owned utilities, and industrial establishments. In 1984, government-owned utilities produced about 83 per cent of total generated electricity, investor-owned utilities about 8 per cent, and industrial establishments the remaining 9 per cent. Over the past fifteen years the percentage of energy produced by industrial establishments has decreased, while that of the utilities has increased (see Table 1).

Industrial establishments generate energy mainly for their own use, although a few sell energy to municipal distribution systems or utilities. About 70 per cent of Canadian industrial establishments with generation facilities are found in Quebec and British Columbia, reflecting the concentration of forest product, mining, and aluminum smelting companies in those two provinces. Over 82 per cent of the electricity generated by industrial establishments is from hydroelectric sources, 9 per cent from natural gas, 4 per cent from oil, and the remainder from other fuels.

Greater public ownership of electric utilities has been the trend in Canada, as provincial governments have taken over most investor-owned electric utilities. However, investor-owned utilities are still a prominent feature of the Canadian industry. Electricity in Prince Edward Island is supplied by an investor-owned utility. In Alberta, two major investor-owned utilities supply about 88 per cent of the electricity consumed in the province and municipally-owned utilities supply most of the remainder. An investor-owned utility in Newfoundland distributes 85 per cent of the electricity used in that province. This utility generates about 15 per cent of its requirements and purchases the remainder mainly from the provincially-owned utility. In the Yukon and Northwest Territories, the federally-owned Northern Canada Power Commission generates and distributes most of the electricity supplied. Two investor-owned utilities supply most of the remainder.

In most provinces, the utilities are fully integrated, from the generation of electricity to its delivery and sale to end users. The principal exception is in Ontario, where about 70 per cent of total electricity supply is purchased from Ontario Hydro and distributed by some 350 municipal utilities.

Table 1. Energy production by utilities and industrial establishments, 1970-1984

Year	Utilities	Industrial Establishments
	(percentage)	
1970	84	16
1975	87	13
1977	88	12
1979	90	10
1981	90	10
1982	90	10
1983	90	10
1984	91	9

Source: Statistics Canada Publications 57-202, 57-001.

Unlike investor-owned utilities, government-owned utilities do not pay income tax. In order to equalize income tax treatment, 95 per cent of federal income taxes paid by investor-owned utilities are refunded to the province of origin under the Public Utilities Income Tax Transfer Act. In the province of Alberta, the tax refund

is returned to electricity consumers. In Prince Edward Island, a portion of the tax refund is returned to utility customers. In Newfoundland, the federal tax refund is retained as general revenues of the provincial government.

The electric power industry is a significant presence within the Canadian economy. As indicated in Table 2, 73 946 people were employed by the industry in 1984. Total assets were $82 billion and long-term debt was $60 billion. The industry's revenues exceeded $14 billion in 1984, 10 per cent of which came from export earnings. Ontario Hydro, Hydro-Québec, and British Columbia Hydro are the three largest electric utilities in Canada and rank first, second and fifth respectively in terms of assets among all Canadian companies. Canadian electricity production relative to that in other countries is shown in Table 3.

Electric Utilities and Their Regulation

Under the Canadian Constitution, primary responsibility for electricity generation, transmission, and distribution rests with the provinces. The only exceptions are with respect to international exports and nuclear power. The National Energy Board, a federally constituted body, regulates all electricity sales from Canada to the United States. The construction and operation of nuclear plants are regulated by another federal tribunal, the Atomic Energy Control Board.

Newfoundland

In Newfoundland, the generation and distribution of electricity is dominated by two utilities, Newfoundland Light & Power Company Limited (NLPC) and Newfoundland and Labrador Hydro (NLH).

NLPC is an investor-owned utility which is involved primarily in distribution. The company was incorporated in 1966 through the amalgamation of St. John's Electric Light Company Limited, United Towns Electric Company Limited, and Union Electric Light and Power Company. Through its predecessors, the company's service dates back to 1895.

NLH is a provincial Crown corporation concerned primarily with electricity generation. It was incorporated in 1975. NLH owns and operates Churchill Falls (Labrador) Corporation Limited (CFLCo). It is also the parent company for the Lower Churchill Development Corporation with 51 per cent ownership, in partnership with the Government of Canada which has a 49 per cent interest. In addition, NLH administers the activities of the Power Distribution District of Newfoundland and Labrador on behalf of the Province, and through CFLCo administers the activities of Twin Falls Power Corporation Limited. NLPC and NLH serve about 200 000 customers.

The two utilities are regulated by the Newfoundland Board of Commissioners of Public Utilities. The Board fully regulates the activities of NLPC. Since 1977, the Board also has had the authority under the Electric Power Control Act to regulate NLH's rates to electricity retailers. The Board has no jurisdiction, however, over rates charged to industrial customers served through NLH's distribution agencies. It makes recommendations to the Newfoundland cabinet regarding NLH's industrial rates. The provincial cabinet is the final regulatory authority.

Table 2. Electric utility assets, debt, revenue and employees, 1984

	($ millions)			
	Assets	Debt	Revenues	Employees
Newfoundland	2 142	1 485	470	2 132
Prince Edward Island	83	28	62	195
Nova Scotia	1 429	1 333	498	2 454
New Brunswick	2 800	2 100	834	2 485
Quebec	27 129	18 326	4 101	18 560
Ontario	27 301	21 506	4 212	29 613
Manitoba	2 806	2 213	506	3 593
Saskatchewan	1 657	1 904	424	3 148
Alberta	4 396	1 946	1 330	4 672
British Columbia	10 579	8 387	1 513	6 764
Yukon/Northwest Territories	273	231	90	330
Canada	81 495	59 560	14 040	73 946

Source: Electric Utilities' Annual Reports.

Table 3. Comparative data of electric utilities in the world's major industrial countries in 1982

	U.S.A.	U.S.S.R.	Japan	Canada	F.R. Germany	U.K.	France	Italy
Generating Capacity (GW)	650	254*	140	85	75	65*	70	39*
Energy Production (TWh)	2 241	1 259*	523	376	304	260*	237	156
Production Per Capita (KWh)	9 944	5 064	4 906	15 283	5 952	4 975*	4 893	3 251
Average Growth Rate of Electricity Production %:								
1972-1977	3.6	6.0	4.5	5.7	4.0	1.2	4.4	4.3
1977-1982	.9	3.5	1.7	3.7	1.8	0.0	5.6	1.9

* Indicates 1981 figures.

Source: Electric Power Industry in Japan 1983, Statistics Canada Publication 57-202.

Prince Edward Island

Maritime Electric Company Limited (MEC) is an investor-owned electric utility which has provided electricity service to Prince Edward Island since 1918. The company owns and operates a fully-integrated electric utility system providing for the generation, transmission, and distribution of electricity throughout the Island. MEC operates two oil-fired generating plants on the Island at Charlottetown and Borden, has a 10 per cent equity interest in New Brunswick Power's dual fuel coal/oil fired No. 2 unit located in Dalhousie, and leases the submarine cable interconnection to New Brunswick owned by the Province of Prince Edward Island. MEC serves about 44 100 customers on the Island. The Town of Summerside has its own distribution system and purchases power from MEC.

MEC is regulated by the Public Utilities Commission of Prince Edward Island under the provisions of the Electric Power and Telephone Act. The Commission has decision-making authority over electric utility rates in the province.

Nova Scotia

In 1972 the Nova Scotia Power Commission (NSPC) bought the shares of the investor-owned Nova Scotia Light and Power Company Limited and in 1973 was incorporated as the present Nova Scotia Power Corporation serving all of the province. NSPC generates most of its electricity from thermal energy, with more than half of the production coming from coal. The Corporation also maintains hydro-generation facilities and purchases power from New Brunswick. The largest portion of the total production of the province is derived from the Lingan Generating Station. In 1984, NSPC served over 341 000 customers.

Prior to 1976, the Nova Scotia government directly set rates and other policies for electric utilities in the province. Since that time, the Board of Commissioners of Public Utilities has taken over this duty and has full decision making power.

New Brunswick

Prior to 1918, more than twenty organizations in New Brunswick, both public and private, were in the business of generating and distributing electricity. In 1918, the government of the day passed an Order-in-Council setting up a Water Power Commission to determine the water power resources of the province. Acting on the recommendation of the Commission, the New Brunswick Electric Power Commission (NB Power) was established by an Act of the New Brunswick Legislature in 1920. The mandate of NB Power is to generate and distribute power under public ownership, to all areas of the province. Electricity is generated from a balance of nuclear, hydro, and thermal sources, and also makes purchases from Quebec. NB Power directly provides electricity for almost 236 000 customers and indirectly serves an additional 37 000 customers through sales to municipal utilities.

The electricity rates of NB Power are not subject to review by any regulatory or judicial authority. Under the provincial Electric Power Act, rates must be sufficient to cover all costs.

Quebec

Hydro-Québec was established by the Legislative Assembly in 1944. After its creation, Hydro-Québec acquired the assets of Montreal Light, Heat and Power Consolidated and Beauharnois Light, Heat and Power Company. In 1963, Hydro-Québec

acquired the remaining ten privately-owned power companies, including the Shawinigan Water and Power Company, Southern Power Company Limited, Québec Power Company and Gatineau Power Company. Several municipal-distribution and public lighting systems were also acquired, together with almost all the electricity cooperatives in Quebec.

Hydro-Québec has two wholly-owned, active subsidiaries: the Société d'Energie de la Baie James (SEBJ), which is carrying out the construction of Phase 1 of La Grande Complex, and Hydro-Québec International, which provides engineering and consulting services abroad for electric power projects. Hydro-Québec is also a shareholder in Churchill Falls (Labrador) Corporation Limited (CFLCo), which operates the Churchill Falls power plant, and in Nouveler Inc., which promotes energy efficiency and alternative energy sources. Currently, Hydro-Québec serves about 2.6 million customers and is responsible for the generation, transmission and distribution of most of the electricity sold in Quebec, the remainder being produced by industrial establishments. Almost all of the electricity generated by Hydro-Québec is from hydro sources.

Rates are fixed by Hydro-Québec and are subject to the approval of the Legislative Assembly.

Ontario

Ontario Hydro is a Crown corporation, established in 1906, by the Provincial Legislature. It has broad powers to produce, buy, and deliver electric power throughout the province and currently operates under the Power Corporation Act. The main responsibility of Ontario Hydro is to provide power to municipal utilities, which in turn distribute power to their own customers. In addition, Ontario Hydro supplies more than one hundred major industrial users directly and about 777 000 rural retail customers in areas or communities not served by municipal utilities. Electricity is generated from a balance of thermal, nuclear, and hydro sources. In 1984, approximately 3.1 million customers were served by Ontario Hydro and the Municipal Utilities in the province.

Ontario Hydro executes its responsibilities with the authority of the Lieutenant Governor in Council. The Minister of Energy may call upon the Ontario Energy Board to review the corporation's rates or rate-making practices. The Board also conducts hearings on bulk power rate revisions, and makes recommendations which are generally accepted by Ontario Hydro.

Manitoba

Manitoba Hydro-Electric Board (Manitoba Hydro) is a Crown corporation established in 1949 by the provincial legislature. It has broad powers to provide electric power throughout the province and operates under the Manitoba Hydro Act. It distributes electricity to consumers throughout the province, except for the central portion of Winnipeg which is served by the city-owned Winnipeg Hydro. Manitoba Hydro and Winnipeg Hydro operate as an integrated electrical generation and transmission system. In 1984, Manitoba Hydro served about 334 000 customers directly. Almost all of the electricity produced is derived from hydraulic sources.

Under the Manitoba Hydro Act, rates are set by Manitoba Hydro and reviewed by the Public Utilities Board. The Board provides advice to the provincial government, leaving the Lieutenant Governor in Council with final authority over pricing and other matters related to the supply of electricity.

Saskatchewan

The Saskatchewan Power Corporation (SPC) was established as a Crown corporation under the 1950 Power Corporation Act. It replaced the Saskatchewan Power Commission, created in 1929 to develop an integrated provincial electrical system. Under the Power Corporation Act, the mandate of the corporation includes the generation, transmission, and distribution of natural gas and electricity. The SPC also began operating the natural gas utility in 1952. At the end of 1984, the corporation was serving about 386 000 customers with electricity and 253 500 customers with natural gas. The bulk of the electricity produced is from thermal sources.

The Power Corporation Act authorizes the Saskatchewan Power Corporation to set rates for natural gas and electricity. These rates, however, are subject to review and approval by the Public Utilities Review Commission of Saskatchewan.

Alberta

There are three major electric utilities in Alberta: TransAlta Utilities Corporation, Alberta Power Limited, and Edmonton Power. Together they supply about 98 per cent of Alberta's electrical energy requirements.

TransAlta Utilities Corporation, formerly Calgary Power Limited, is the largest investor-owned electric utility in Canada. The company was incorporated under the laws of Canada and has been engaged in the production and distribution of electricity in the Province of Alberta since 1911. Over 74 per cent of the electric energy requirements of Alberta and over half of the population are supplied by the company. At the end of 1984, about 280 000 customers were served directly. Almost all of the electricity generated is from coal.

Alberta Power Limited, incorporated in 1972, is another investor-owned electric utility in Alberta, and a subsidiary of Canadian Utilities Ltd. The activity of the company is concentrated in east-central and northern Alberta. Alberta Power supplied about 17 per cent of the total Alberta electricity requirements in 1984, serving about 140 000 customers. Almost all of the electricity generated is also from coal.

Edmonton Power is Alberta's second largest electric utility and the largest municipally-owned utility in terms of generating capacity in Canada. Since its creation in 1902, Edmonton Power has kept pace with the growth and development of Edmonton. The utility produced slightly over 7 per cent of the electricity requirements of Alberta in 1984 and served more than 224 000 customers.

The utilities are regulated by the Energy Resources Conservation Board, with respect to the development of generation and transmission facilities. Hydro and thermal plant construction and operation require Board approval, with authorization from the Lieutenant Governor in Council. In addition, hydro construction requires statutory authorization.

Electricity rates are regulated by the Public Utilities Board. The three utilities sell energy at "pooling interfaces" to the Electrical Energy Marketing Agency (EEMA) at prices established by the Board based on their upstream costs. EEMA sells the electricity back to the utilities at an average price to reduce price disparities in the province. The Public Utilities Board also has jurisdiction over the consumer rates and service of investor-owned utilities. Edmonton Power is exempt from this control as it is a municipally-owned utility.

British Columbia

British Columbia Hydro and Power Authority (B.C. Hydro), incorporated in 1961, is a Crown corporation operating in British Columbia. B.C. Hydro provides electrical service throughout the province, with the exception of the area served by Cominco Limited and its subsidiary, West Kootenay Power and Light Company Limited. B.C. Hydro is the third largest electric utility in Canada and the largest distributor of natural gas in British Columbia. B.C. Hydro generates, transmits, and distributes electricity to more than one million customers in a service area which contains more than 90 per cent of the population of British Columbia. It also distributes natural gas in Greater Vancouver and in the Fraser Valley, and propane-air gas in Greater Victoria.

The British Columbia Utilities Commission (BCUC) has general supervision powers over B.C. Hydro. Jurisdiction extends to system expansion operation, financial transactions, and rate schedules. Cominco is exempted from this general regulation, subject to its compliance with several terms and conditions related to its pricing structure and use of facilities. New electricity exports require removal permits granted by the BCUC, after authorization by the Lieutenant Governor in Council.

Yukon and Northwest Territories

The Northern Canada Power Commission (NCPC) is a federal Crown corporation, created in 1956, under authority of the Northern Canada Power Commission Act. It is concerned with the planning, construction and management of utilities on a commercial basis. The Commission is the principal producer of electricity north of 60° and operates the main transmission networks in the north. Currently the NCPC serves more than 12 000 customers.

Under the Northern Canada Power Commission Act (NCPCA), the Commission is to be self-sustaining within the rate zones of the Yukon and Northwest Territories. To ensure this, rates charged by utilities must provide sufficient revenue to cover capital and operating costs of the Commission. The Commission, although under no legal obligation to do so, generally abides by the recommendations of the Yukon and Northwest Territories Public Utilities Boards provided that the recommendations do not conflict with the requirements of the NCPCA.

DOMESTIC ELECTRICITY CONSUMPTION

Electricity Consumption in 1984

Canada's electricity demand grew 7.1 per cent in 1984, the highest annual increase since 1976. This increase can be attributed primarily to economic growth. Real Gross Domestic Product grew 4.7 per cent in 1984, also the highest annual increase since 1976. A move towards electric heating and away from oil also contributed to the growth in electricity consumption. Over the period October 1980 to December 1984, approximately 900 000 households have been converted from oil to alternative energy sources. The largest share of these conversions was from oil to electricity, representing 41 per cent of the total. A colder winter in 1984 relative to 1983 also affected electricity demand favorably.

Because of the strong increase in electricity demand, the electricity factor in the Canadian economy in 1984 continued to increase. The quantity of electricity consumed, expressed in kilowatt-hours per dollar of real GDP (1971$), was 3.09 in 1984, up from 3.02 in 1983, 2.65 in 1975, and 2.58 in 1970.

Table 4 presents the 1984 growth rates in electricity demand by province and by major utility. Growth rates vary considerably by province from a high of 12.3 per cent for New Brunswick to a low of 1.9 per cent for British Columbia. Of the major utilities, Hydro-Québec experienced the largest growth rate, at 12.7 per cent, followed by the New Brunswick Power Commission and Saskatchewan Power Corporation, with increases of 12.2 per cent and 10.1 per cent respectively.

Table 4. Percentage growth in electricity demand, 1984

	Province	Major Utilities
Newfoundland	5.7	4.8
Prince Edward Island	2.0	2.0
Nova Scotia	7.0	6.7
New Brunswick	12.3	12.2
Quebec	10.6	12.7
Ontario	5.5	5.8
Manitoba	2.9	4.6
Saskatchewan	10.1	10.1
Alberta	6.9	5.9
British Columbia	1.9	5.0
Yukon/NWT	9.5	7.6
Canada	7.1	8.4

Source: Energy, Mines and Resources Canada.

Electricity demand by sector, for the period 1979-84 is reported in Table 5. The industrial sector consumes the largest share of electricity. In 1984, this sector accounted for 50 per cent of total consumption, followed by the residential sector with 28 per cent, and the commercial sector with 22 per cent.

Forecast Demand

Forecasting electricity demand has become a more difficult task during the past ten years or so as a result of the economic dislocations caused by rapidly rising energy prices. The effects were felt on a global scale and major adjustments were made in the amounts and types of energy used. The decline in the international price of oil in the past couple of years has added to the uncertainty. Adjustments in energy consumption patterns continue to make economic forecasting difficult.

Table 5. Total electricity demand in Canada by sector, 1979-1984

	1979		1980		1981		1982		1983		1984	
	GWh	%	GWh	%	GWh	%	GWh	%	GWh	%	GWh	%
Residential and Farm	87 638	27	92 669	27	95 048	28	99 248	29	101 101	28	107 945	28
Commercial	72 384	22	73 450	22	75 681	22	77 770	22	80 753	22	84 814	22
Industrial	163 443	51	173 949	51	175 526	50	168 421	49	177 910	50	192 757	50
Total	323 465	100	340 068	100	346 255	100	345 439	100	359 764	100	385 515	100

Source: Statistics Canada Publication 57-202, 1979-1983.
Data for 1984 is preliminary.

FIGURE 1

HISTORICAL RELATIONSHIP BETWEEN PER CAPITA ELECTRICITY DEMAND AND PER CAPITA GROSS DOMESTIC PRODUCT

1960-1984

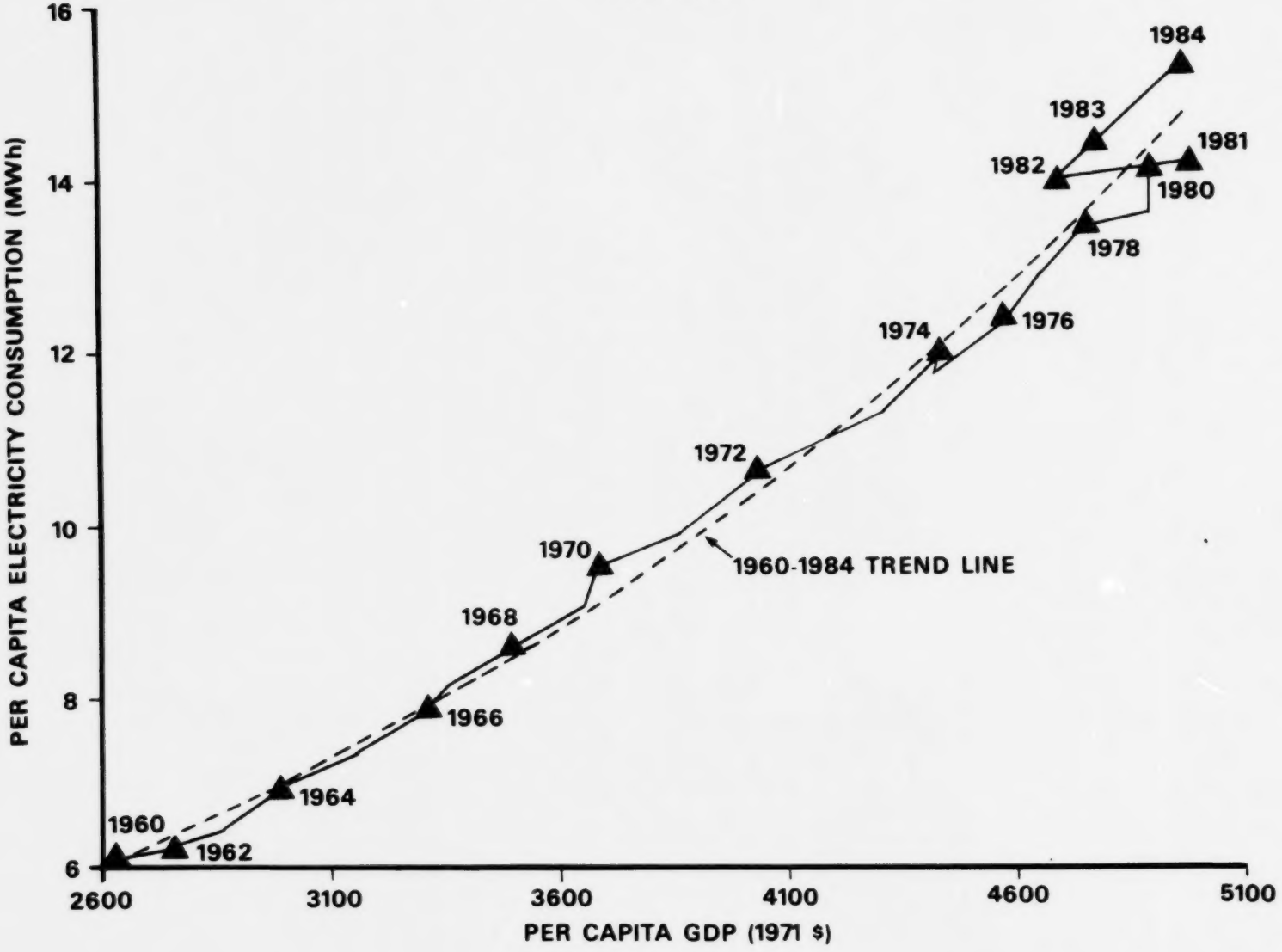


Figure 1 shows the close historical relationship between per capita economic performance, as measured by Gross Domestic Product (GDP), and per capita electricity demand.

Table 6 presents the growth, over the period 1960-1984, of real GDP (i.e. GDP net taking account of inflation), population, primary energy demand (i.e. the total energy available from the energy sources in their original state), and electrical energy demand. Table 6 also presents the forecasts prepared by the Department of Energy, Mines and Resources (EMR), for each of these variables for the period 1984-2000.

Since economic growth and population growth over the next sixteen years are expected to be significantly lower than that of the previous twenty-five year period, electricity growth is also expected to be lower. However, the forecasts presented in Table 6 also indicate an increasing role for electrical energy in Canada. The percentage of primary energy supplied in the form of electricity is expected to increase from 42 per cent in 1984 to about 44 per cent in 1990 and 46 per cent in the year 2000.

Table 6. Historical and forecast annual growth rates

	(per cent)		
	1960-84	1973-84	1984-2000
Real GDP	4.2	2.5	3.0
Population	1.4	1.2	0.7
Primary Energy	3.6	1.4	2.5
Electrical Energy	5.4	3.7	2.9

Source: Energy, Mines and Resources Canada.

The long (5-10 years) lead times required to bring new generation facilities into service requires forecasts of future demand. Thus despite the inherent difficulties, forecasts must be made. Forecasts of the growth in electricity demand, prepared by the major utilities and provided to EMR in January 1985, are summarized in Table 7. The extent of the changed perception of future demand is illustrated by the forecasts provided by the utilities last year, shown in brackets in Table 7. With the exceptions of Prince Edward Island, Nova Scotia, and New Brunswick, all electric utilities reduced their forecast demand growth over the period 1984-2000 from the forecasts provided in January 1984.

Table 7. Utility forecasts of electricity demand (per cent)

	1984-1990	1990-2000	1984-2000
Nfld.	2.8 (4.0)	2.9 (4.3)	2.8 (4.2)
P.E.I.	3.9 (1.0)	2.7 (1.0)	3.2 (1.0)
N.S.	4.3 (3.8)	3.7 (3.7)	3.9 (3.7)
N.B.	3.1 (3.2)	2.3 (2.2)	2.6 (2.6)
Que.	2.6 (2.9)	2.0 (2.9)	2.2 (3.1)
Ont.	2.2 (2.8)	2.3 (2.2)	2.2 (2.5)
Man.	2.5 (3.3)	2.5 (2.8)	2.5 (3.0)
Sask.	2.2 (2.9)	2.2 (2.5)	2.2 (2.6)
Alta.	4.3 (4.5)	3.6 (4.1)	3.9 (4.2)
B.C.	2.1 (2.7)	1.4 (2.5)	1.7 (2.6)
N.W.T/ Y.T.	1.0 (3.7)	0.5 (1.5)	0.7 (2.3)
Canada	2.6 (3.0)	2.2 (2.6)	2.4 (2.8)

Source: Energy, Mines and Resources Canada - Utility Questionnaire.

The significantly reduced electricity demand forecasts illustrate how difficult it is to forecast electricity demand with a high degree of confidence. Rather than single value

forecasts, most utilities are now considering a range of demand forecasts with an assignment of statistical probability to each. As well, they are adopting an approach to planning which emphasizes flexibility. Rather than plan generation capacity to meet whatever demand develops, they are taking steps to alter peak demand requirements by means of direct load management, while simultaneously ensuring that generating capacity is sufficient to meet demand under reasonable assumptions regarding future growth.

Figure 2 illustrates various forecasts for electricity demand. Included on the bar chart for comparison are the National Energy Board 1984 base case, the latest forecast derived from EMR's Interfuel Substitution Demand Model, and the forecast developed by the EMR Electrical Energy Branch on the basis of projections provided by the major utilities.

Peak Demand

Peak demand in Canada grew by 3.6 per cent in 1984, up from 67 000 MW in 1983 to about 69 000 MW in 1984. Based on the electric utilities' projections, peak demand is expected to increase annually by 2.1 per cent, to 97 000 MW by the year 2000. Table 8 reports the forecast peak demand growth rates for all provinces and territories, as projected by the major electric utilities for the period 1984-2000.

Load Factor

As was pointed out earlier, energy demand grew faster than peak demand in 1984. The growth rate was 7.1 per cent for energy compared with 3.6 per cent for peak; load factor for Canada as a whole, therefore, increased by 3.4 per cent, from 61.6 per cent in 1983 to 63.7 per cent in 1984. Load factors for each province and Canada during the period 1984-2000 are reported in Table 9.

Table 8. Peak demand growth rates (per cent)

	1984-1990	1990-2000	1984-2000
Nfld.	2.3	3.2	2.9
P.E.I.	3.2	2.7	2.9
N.S.	4.3	3.8	4.0
N.B.	4.7	2.3	2.9
Que.	-0.1	2.2	1.3
Ont.	2.3	2.2	2.3
Man.	3.6	2.5	2.9
Sask.	2.7	2.1	2.3
Alta.	4.3	4.0	4.1
B.C.	1.7	1.6	1.6
N.W.T./ Y.T.	1.1	0.5	0.7
Canada	1.7	2.4	2.1

Source: Energy, Mines and Resources Canada - Utility Questionnaire.

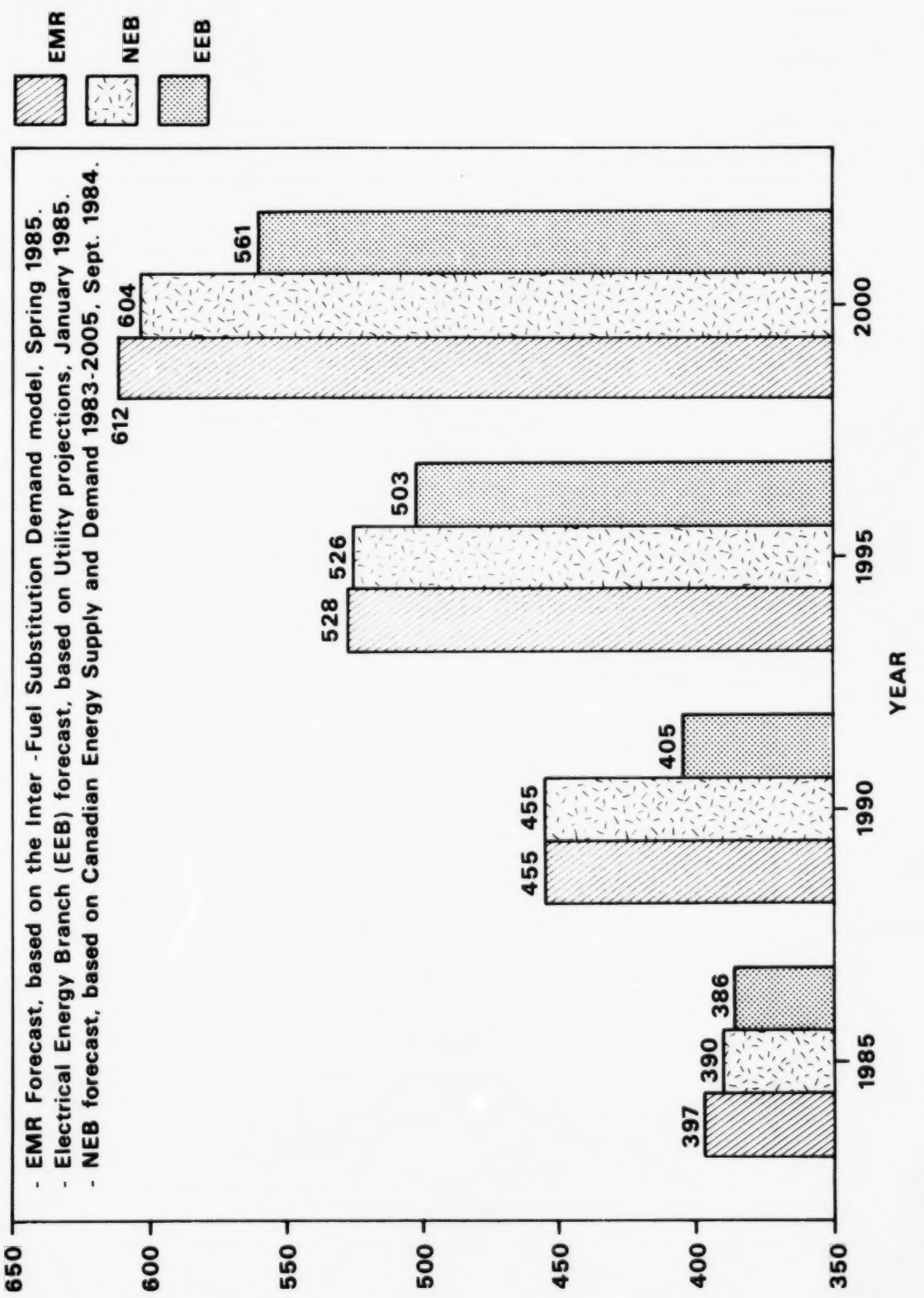
Table 9. Load Factor in Canada (per cent)

	1984	1990	2000
Nfld.	53.6	55.0	53.2
P.E.I.	57.7	60.4	60.5
N.S.	62.9	62.8	62.2
N.B.	62.5	59.2	59.2
Que.	61.4	72.4	71.0
Ont.	67.3	66.9	67.1
Man.	60.0	56.2	56.1
Sask.	61.2	59.4	59.8
Alta.	70.3	70.2	67.4
B.C.	62.9	64.5	63.1
N.W.T./ Y.T.	55.0	54.9	54.9
Canada	63.7	67.2	66.3

Source: Energy, Mines and Resources Canada - Utility Questionnaire.

FIGURE 2

ELECTRICAL ENERGY FORECASTS



GENERATING CAPACITY

New Additions

Total generating capacity increased by 6 250 MW in 1984 to 95 530 MW at year end, a 6.7 per cent increase over 1983. Hydro capacity additions totaled 3 857 MW, nuclear 1 816 MW, and conventional thermal 577 MW, representing 62 per cent, 29 per cent, and 9 per cent of the total additions respectively. A summary of the major additions is presented in Table 10.

Total installed capacity by principal fuel type by province for 1984 is illustrated in Figure 3. Installed capacity by region and installed capacity by energy source for Canada, are shown in Figures 4a and 4b. Figure 5 presents a graph indicating historical installed capacity for Canada during the period 1960-1984. Although the market share of hydro has decreased since 1960, it is still the most important electric power source in Canada. In 1984, hydro accounted for 59 per cent of total installed generating capacity.

Table 10. Major changes to installed generating capacity during 1984

	Project	Plant Type	No. of Units	Capacity MW
Additions				
Nova Scotia	Lingan	Steam (coal)	1	150
	Annapolis Royal	Hydro	1	20
Quebec	La Grande 3	Hydro	2	384
	La Grande 4	Hydro	7	2051
Ontario	Bruce B	Nuclear	1	784
		Gas Turbine	2	33
	Pickering B	Nuclear	2	1032
Alberta	Keephills	Steam (coal)	1	394
British Columbia	Revelstoke	Hydro	3	1382
Yukon	Whitehorse #4	Hydro	1	20

Source: Energy, Mines and Resources Canada - Utility Questionnaire.

FIGURE 3

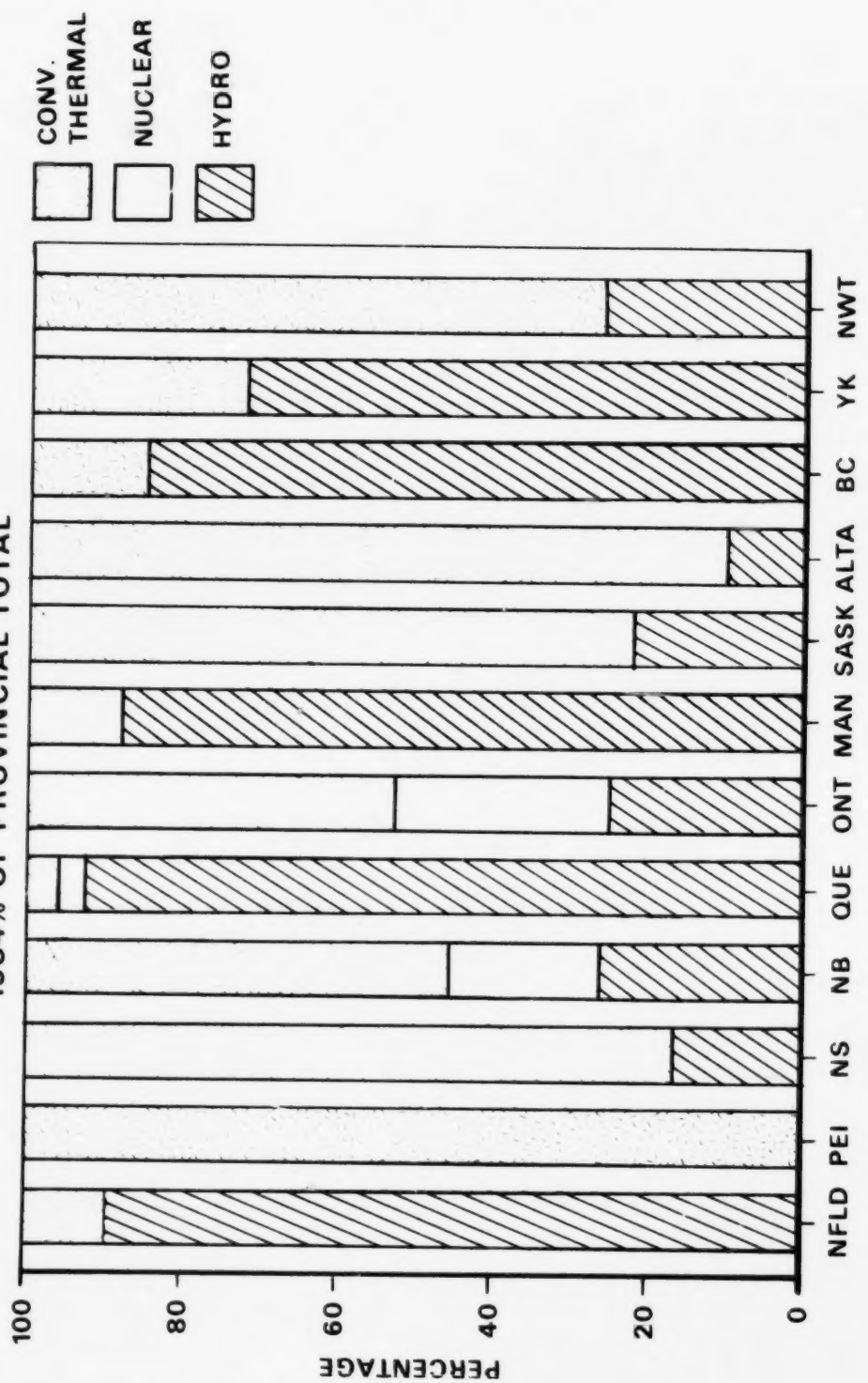

INSTALLED CAPACITY BY PRINCIPAL FUEL TYPE
1984% OF PROVINCIAL TOTAL
CONV. THERMAL
NUCLEAR
HYDRO
PERCENTAGE
100
80
60
40
20
0
NFLD PEI NS NB QUE ONT MAN SASK ALTA BC YK NWT
PROVINCE

Figure 4a

CAPACITY BY REGION 1984

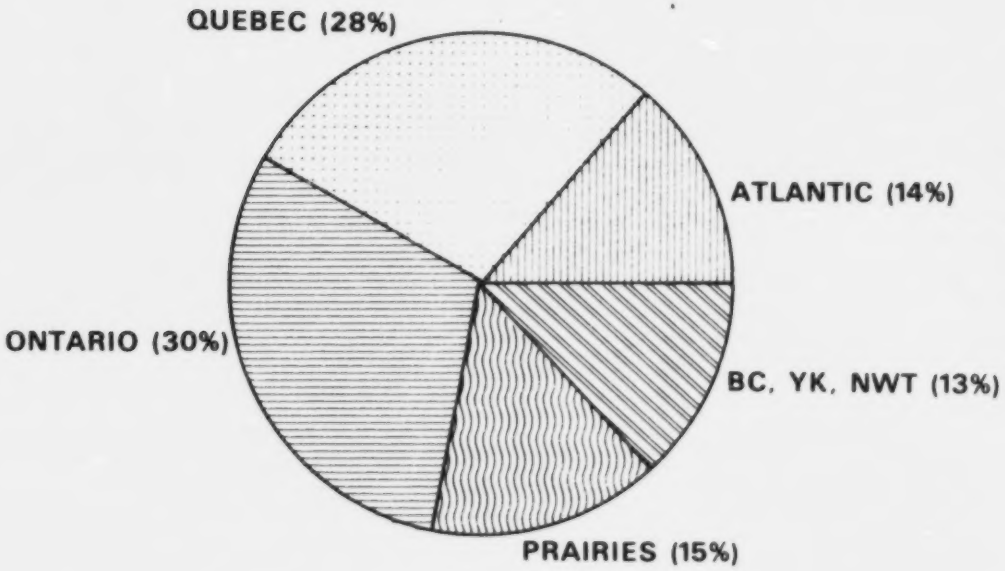


Figure 4b

CAPACITY BY ENERGY SOURCE 1984

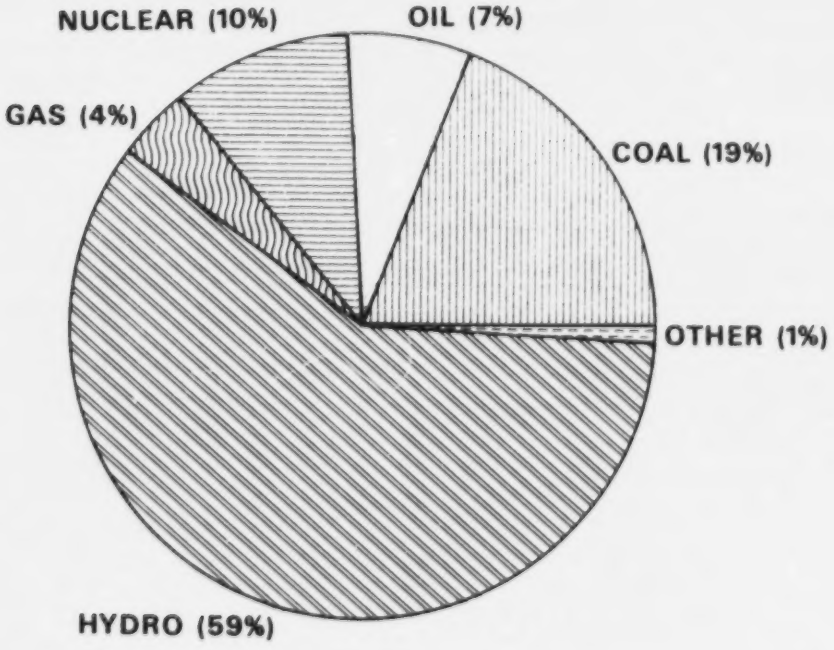
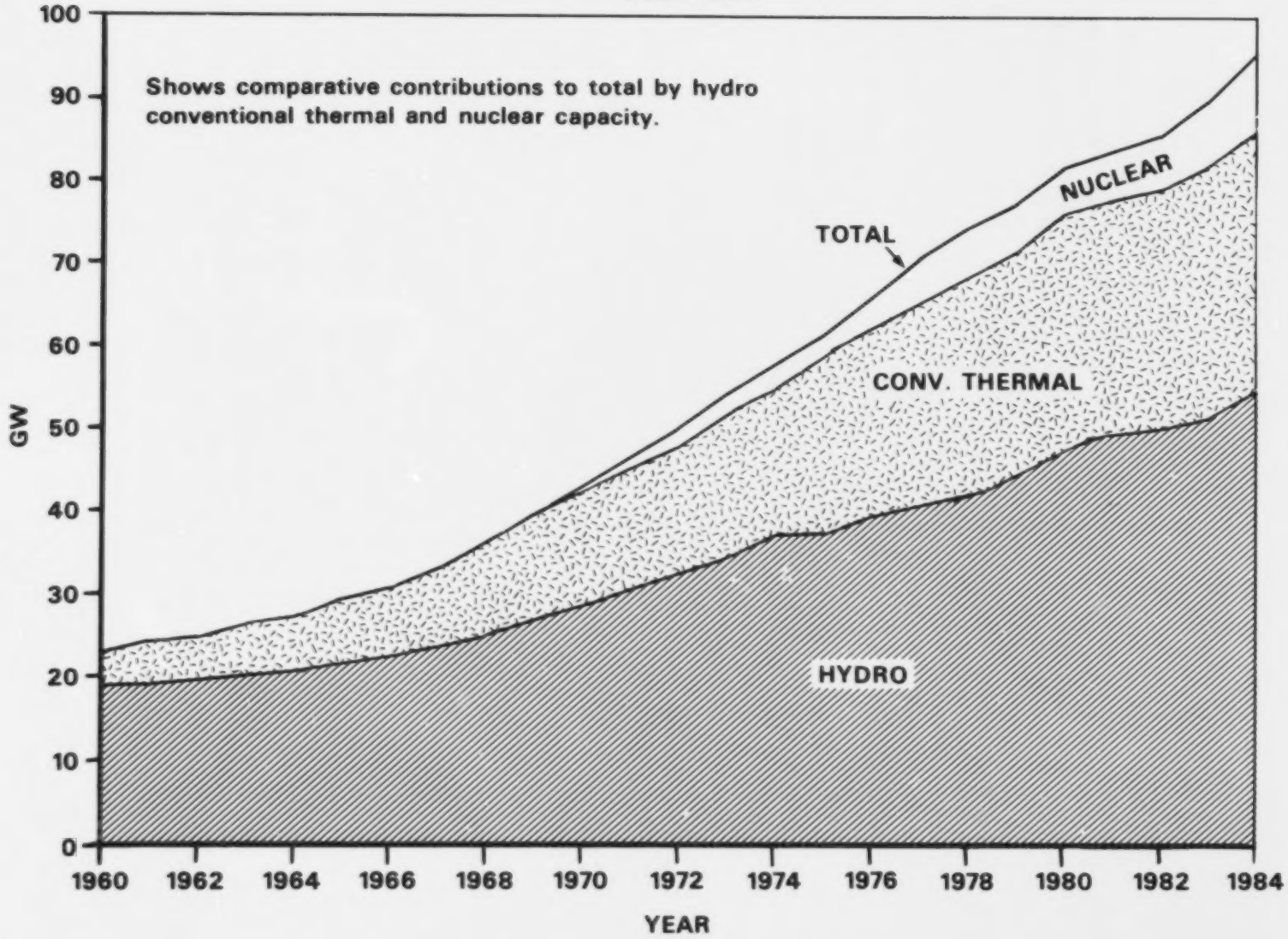


FIGURE 5

HISTORICAL INSTALLED CAPACITY, 1960-1984



Forecasts of Generating Capacity

To meet the forecast growth in electricity demand, total installed generating capacity in Canada is expected to increase at an average annual rate of 1.5 per cent, from 95 000 MW in 1985 to 118 000 MW by the end of the century. The fact that this level of growth is significantly less than energy and peak demand growth, reflects the current excess capacity situation in certain provinces, notably Nova Scotia, New Brunswick, Quebec, Ontario, Manitoba, and British Columbia. Capacity, by energy source, is displayed in Table 11.

The largest share of total Canadian capacity over the next 15 years will continue to be hydro, with its 57 per cent share of total capacity remaining relatively stable through the period. Nuclear installed capacity will increase considerably between 1985 and 1990, but will experience slow growth in the 1990s. Nuclear generating capacity, as a share of total capacity, is expected to increase from 10 per cent in 1985 to 13 per cent in 1990, and to stabilize thereafter.

While coal-fired capacity is expected to increase moderately over the forecast period, its capacity share is expected to be fairly stable at about 19 per cent of total capacity. Natural gas capacity will decrease gradually, from 4 per cent in 1985 to 3 per cent by 2000.

Oil-fired capacity is expected to increase slightly over the period, although its share of total capacity is expected to remain stable at about 7 per cent. Oil will be used primarily for peaking purposes; coal, nuclear, and hydro will continue to account for most of the electricity generated in Canada. These latter sources accounted for 88 per cent of total capacity in 1984, and this percentage is expected to increase slightly by the year 2000.

Table 11. Forecasts of installed generating capacity by principal fuel type - Canada

	Installed Generating Capacity (MW)							Percentage of Installed Capacity						
	Coal	Oil	Natural Gas	Nuclear	Hydro	Other	Total	Coal	Oil	Natural Gas	Nuclear	Hydro	Other	Total
1985	17.9	7.3	3.6	10.0	55.7	0.5	95.0	19	8	4	10	58	1	100
1990	18.7	7.3	3.4	13.6	58.6	0.6	102.2	18	7	4	13	57	1	100
1995	20.4	7.2	3.7	15.3	61.8	0.8	109.2	19	7	3	14	56	1	100
2000	22.7	8.1	3.4	15.3	67.1	1.0	117.6	19	7	3	13	57	1	100

Source: Energy, Mines and Resources, based on forecasts provided by the Utilities and the National Energy Board.

RESERVE MARGINS

There have been two distinct periods in the growth of electricity demand in Canada since World War II. From 1947 to 1974 there was a period of rapid growth, with an average annual increase of 6.8 per cent. Following the oil crisis of 1973-1974, electricity growth slowed to an average rate of 3.4 per cent for the period 1975-1984. During the latter period, electricity consumption actually declined in 1975 and again in 1982.

This shift, from a long period of sustained rapid growth to one of slower growth, resulted in excess generating capacity. In the early 1970s, the construction of new generating stations was initiated on the basis of expectations of continuing rapid growth in electricity demand. As the growth in demand slowed dramatically in the latter part of the decade, some of these newly constructed stations became surplus to requirements.

Present Reserve Margin

For an electrical system, the per cent reserve margin is defined as the excess of installed generating capacity over annual peak load expressed as a per centage of annual peak load. Table 12 presents the reserve margin in all ten provinces. The highest reserve is in New Brunswick with 57 per cent, followed by Nova Scotia with 55 per cent, British Columbia with 47 per cent, and Ontario with 41 per cent. No new generating plants are now under construction in New Brunswick, Nova Scotia, and British Columbia. Other than the four units at the Darlington nuclear facility, which will be completed in 1992, no additional units are presently committed in Ontario.

Capacity Reserve Requirements

Normal practice in an electrical system is that a certain proportion of installed capacity is designated to allow for scheduled maintenance, planned outage, and unexpected peak demand. This proportion is usually called the capacity reserve requirement. It varies from utility to utility depending on the installed capacity mix of the electrical system. Table 12 reports the capacity reserve requirement in each province. Ontario Hydro has the largest capacity reserve while Hydro-Québec has the lowest.

Surplus Generating Capacity

Surplus generating capacity is defined as the reserve margin less the reserve capacity requirement. Table 11 indicates surplus generating capacity by province for 1984. With the exception of Prince Edward Island, all provinces had surplus capacity. In New Brunswick, Nova Scotia, and British Columbia, the surplus exceeded 30 per cent. The weighted surplus for Canada as a whole was 21 per cent.

Table 12. Surplus of installed generating capacity in 1984

	Reserve Margin (1)	Capacity Reserve Requirement (2)	Net Surplus (3) = (1) - (2)
Newfoundland	39	12	27
Prince Edward Island	16	20	-4
Nova Scotia	55	20	35
New Brunswick	57	20	37
Quebec	28	10	18
Ontario	41	25	16
Manitoba	37	15	22
Saskatchewan	18	15	3
Alberta	38	22	16
British Columbia	47	15	32
Canada	35	14	21

Source: Energy, Mines and Resources Canada.

ENERGY SUPPLY

Energy Generation

Electricity generation increased 7.4 per cent in 1984 to 425 TWh. Of this, 386 TWh was for use in Canada and the remainder was exported. The sources of generation were as follows:

Source of electricity production

Generation Type	% of 1984 Generation	% Increase from 1983
Hydro	66.7	7.7
Thermal	21.7	6.7
Nuclear	11.6	6.6

Source: Energy, Mines and Resources Canada - Utility Questionnaire.

The increased hydro generation was mainly attributable to new production from James Bay (12 000 GWh) and Revelstoke (10 800 GWh), and to increased production from Churchill Falls (5000 GWh). Electricity production from fossil fuels increased by 6.7 per cent in 1984 over 1983. The fossil fuel share of total electricity production was 22 per cent, the same as the previous year. The production of electricity from coal increased by 11 per cent, while generation from oil and gas decreased by 3 per cent and 34 per cent respectively. Total nuclear production increased by 6.6 per cent.

Energy production by fuel type and province is shown in Figures 6 and 7. The major increases in coal-fired production were in Nova Scotia (28 per cent), Saskatchewan (22 per cent), and Alberta (17 per cent). In New Brunswick, coal production declined by 45 per cent. Natural gas is used for electricity production primarily in Alberta, British Columbia, and Ontario. Production declined by 57 per cent in Alberta, 13 per cent in Ontario, and 6 per cent in British Columbia.

Oil-fired production declined in Newfoundland as a result of increased hydro generation and in Nova Scotia as a result of displacement by coal-fired production. New Brunswick increased oil-fired production because of its export commitment. It is estimated that about 80 per cent of electricity generated from oil was exported to the U.S.

Nuclear generation was 11.6 per cent of the total in 1984. In Quebec, the Gentilly II station increased its generation substantially from 1990 GWh in 1983 to 3422 GWh in 1984. In Ontario, three new nuclear units were put in service, and the remaining increase for the year came from increased production in New Brunswick.

FIGURE 6

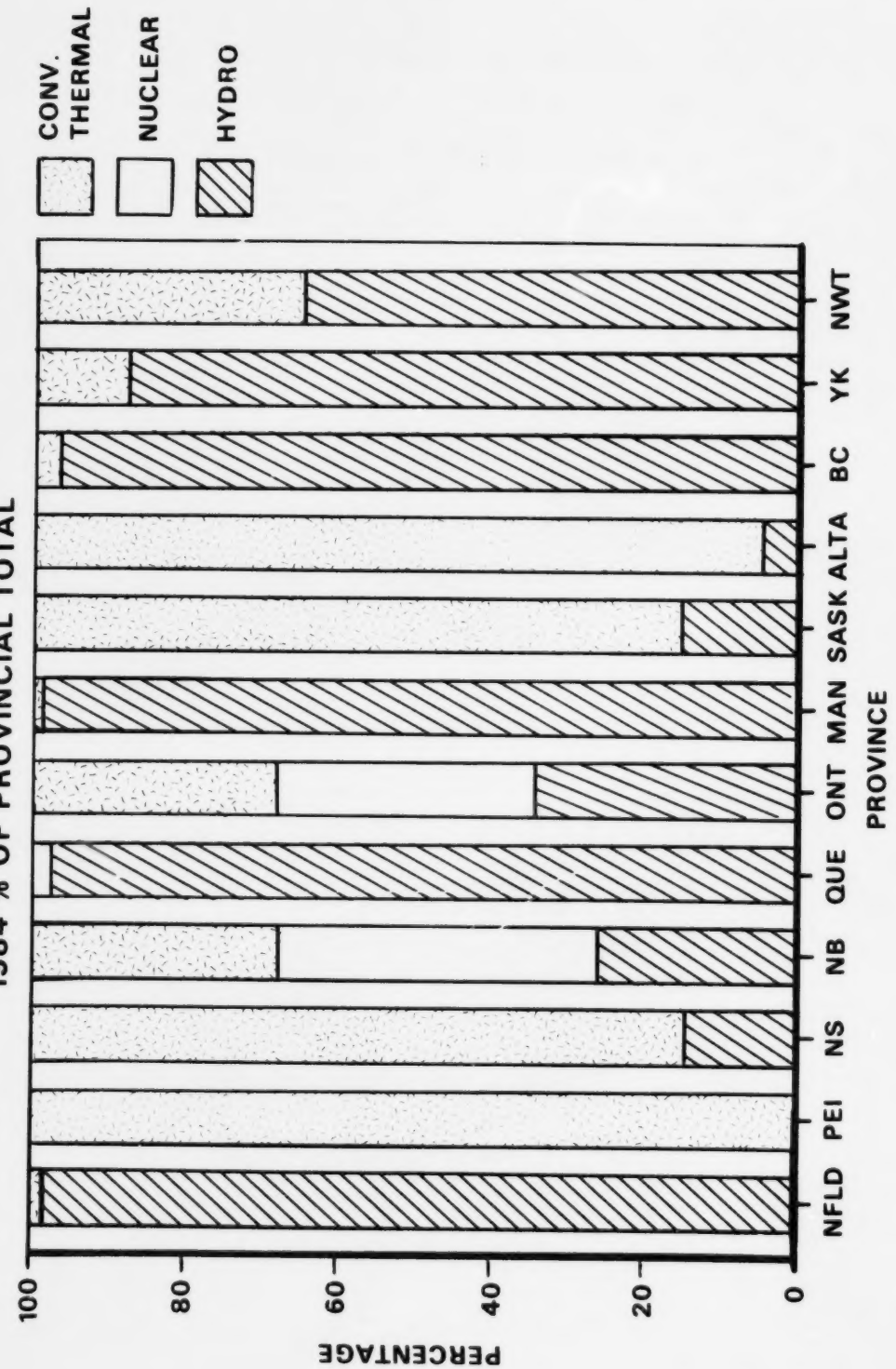

ENERGY GENERATION BY PRINCIPAL FUEL TYPE
1984 % OF PROVINCIAL TOTAL
CONV. THERMAL
NUCLEAR
HYDRO
PERCENTAGE
100
80
60
40
20
0
NFLD
PEI
NS
NB
QUE
ONT
MAN
SASK
ALTA
BC
YK
NWT
PROVINCE

Figure 7a

PRODUCTION BY REGION 1984

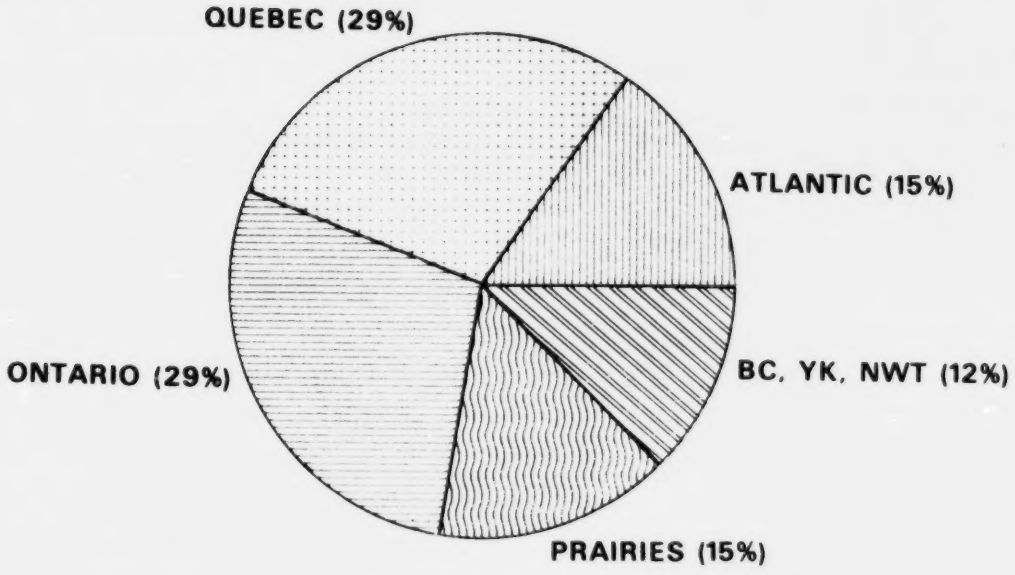
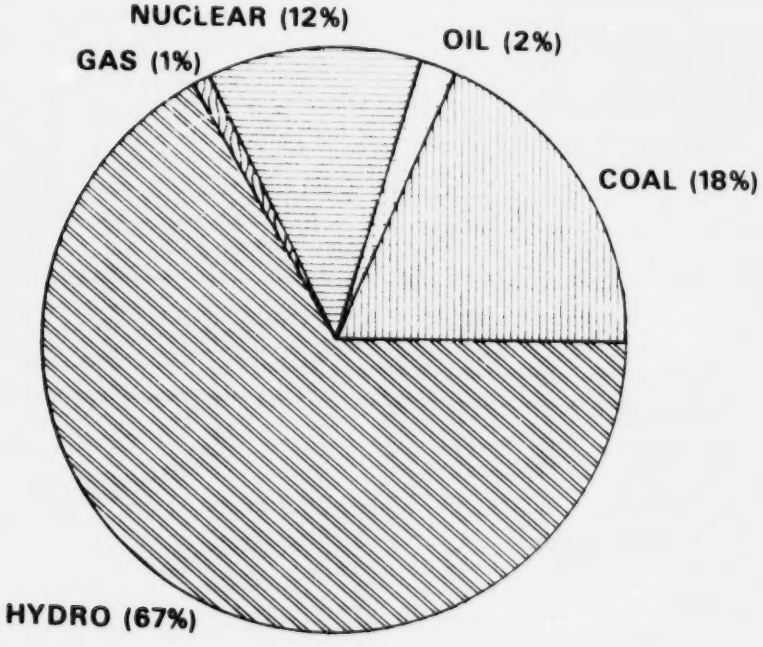


Figure 7b

PRODUCTION BY ENERGY SOURCE 1984



Forecast of Energy Generation

Utility forecasts of electricity generation, by principal fuel type for Canada, are presented in Table 13. The data suggest that hydro-based generation will continue to be the most important source of electric energy in Canada, although its share of total electricity production will decline slightly, from about 67 per cent in 1985, to about 62 per cent in 2000. Coal-fired production is expected to decrease, in both quantity and market share, between 1985 and 1990, and then steadily increase to 16 per cent of total electricity generation by the year 2000. Ontario Hydro is the main factor in this decrease, because it plans to reduce its coal-fired generation from 37 TWh in 1984, to only 13 TWh by 1990. This substantial reduction will be offset by increasing nuclear production from the Darlington nuclear stations.

Oil-fired stations will continue to be used as peaking capacity and to serve energy demand in remote locations. Beyond 1990, the use of oil in electricity generation is expected to increase with the overall increase in demand. By the year 2000, the share of electricity generated from oil is expected to reach 2 per cent of total electricity generation. Natural gas will continue to be used sparingly, accounting for only about 1 per cent of total electricity generation throughout the period.

Nuclear generation is forecast to increase at an average annual rate of 4.9 per cent between 1985 and the year 2000. Its share of electricity generation is expected to increase from 14 per cent to about 18 per cent over the same period.

Table 13. Forecasts of energy generation by fuel type - Canada

	Energy Generation (TWh)							Percentage of Generation						
	Coal	Oil	Natural Gas	Nuclear	Hydro	Other	Total	Coal	Oil	Natural Gas	Nuclear	Hydro	Other	Total
1985	71.4	6.7	4.9	61.0	298.1	2.3	444.4	16	1	1	14	67	1	100
1990	64.9	6.8	4.7	99.2	320.2	3.1	498.9	13	1	1	20	64	1	100
1995	74.3	8.2	6.9	111.7	339.9	4.0	545.3	14	1	1	21	62	1	100
2000	100.1	9.4	6.3	106.1	370.2	6.0	598.1	16	2	1	18	62	1	100

Source: Energy, Mines and Resources, based on forecasts provided by the Utilities and the National Energy Board.

ELECTRICITY TRADE

International Trade

Canada's international electricity trade for the period 1980-1984 is summarized in Table 14. Net electricity exports to the United States increased by 10 per cent in 1984, as did net revenue. Total exports were 41 435 GWh, while imports were 2343 GWh. About 71 per cent of the electricity exported in 1984 was interruptible; that is, it was available only when surplus to the selling utility's needs. Hydro-generated electricity continued to account for more than half of the total exported.

The provincial sources of exports and the average revenue received since 1982 are shown in Table 15. Three provinces - New Brunswick, Quebec, and British Columbia - showed increases during 1984.

British Columbia's exports increased dramatically during the third quarter of 1984, with increased demand for Canadian electricity by the City of Los Angeles, but dropped in the last quarter after the implementation of a new intertie access policy by Bonneville Power Administration (BPA) in the United States. BPA owns and operates the transmission system from the U.S. Northwest, to the California/Oregon border, and the new intertie policy gives Northwestern U.S. utilities preference over Canadian utilities. The increases in Quebec resulted from greater interruptible sales arising from new contracts with the Power Authority of the State of New York. Ontario Hydro lost some nuclear generation in 1984 because of outages of certain nuclear units. This loss of generation, along with increased competition in the Michigan and New York markets, contributed to a decline in Ontario Hydro's interruptible sales. Exports from Manitoba and Saskatchewan also declined in 1984.

The average revenue received from electricity exports during 1984 varied significantly from province to province. New Brunswick received the highest average revenue, $61.5 per megawatt hour, while British Columbia received the lowest, $15.3 per megawatt hour. The factors which affect the value of electricity exports include whether the electricity is exported on a firm or interruptible basis, the generating costs of the exporting utility, the generating costs avoided by the importing utility, and the cost of transmission. Interruptible electricity supply is less valuable to the importing utility since it must maintain standby generating capacity. The generating costs incurred by the exporter and avoided by the importer vary according to the type of electricity generation. For base load generation in both Canada and the United States, oil-fired generating plants tend to be the most costly and hydro the least costly.

Table 16 presents the proportion of firm and interruptible electricity exports for each province. While firm exports accounted for just under 30 per cent of total Canadian electricity exports in 1984, the proportion of firm to total exports ranged from 8 per cent in British Columbia to 100 per cent in Saskatchewan.

Table 17 presents the energy sources of electricity exported during 1984. Exports from Quebec, Manitoba, and British Columbia were generated almost entirely from hydroelectric stations, while exports from Ontario were generated primarily from thermal stations using imported coal. In New Brunswick, the generation sources were nuclear, oil, and coal.

The export market areas, and the types of electricity generation displaced by Canadian exports, are presented in Table 18. In all markets, Canadian exports displaced electricity which would have otherwise been generated from fossil fuels.

Table 14. International electricity trade, 1980-1984

	1980	1981	1982	1983	1984
			(GWh)		
Exports[a]	28 229	34 730	32 986	36 907	37 572
Imports[a]	169	466	268	211	291
Net exports	28 060	34 264	32 718	36 686	37 281
Type of exports[b]					
Firm	7 236	5 008	5 829	10 218	10 852
Interruptible	20 993	29 722	27 157	26 689	26 720
Total	28 229	34 730	32 986	36 907	37 572
Generation source for exports:[c]					
Hydro	12 336	19 948	18 574	19 237	20 555
Imported coal	10 599	10 901	10 315	11 704	10 582
Imported oil	2 867	1 940	1 959	1 201	1 552
Domestic coal/oil	593	665	502	519	711
Nuclear	30	42	96	1 856	1 911
Other[d]	1 804	1 234	1 540	2 390	1 352
Total	28 229	34 730	32 986	36 907	36 663
Revenue/Cost			(million $)		
Exports	793.58	1143.87	1105.90	1249.00	1376.00
Imports	2.94	5.62	5.41	5.80	9.61
Net revenue	790.64	1138.25	1100.49	1243.20	1366.39

(a) Excludes no-value exchanges.
(b) Firm exports refer to energy that must be made available when the purchaser wants it. Interruptible exports refer to energy that is made available by the supplier only when surplus energy exists.
(c) Estimated from data of major utilities.
(d) Includes purchases for export where the generation source is not identifiable.

Source: National Energy Board.

Table 15. Electricity exports and revenues by province, 1982-1984

	1982		1983		1984		% Change
	Exports GWh	Revenue $/MWh	Exports GWh	Revenue $/MWh	Exports GWh	Revenue $/MWh	in Exports 1983 to 1984
N.B.	2 989	53.2	5 311	51.2	5 693	61.5	7
Que.	8 535	34.3	10 225	33.2	11 240	34.5	10
Ont.	11 136	38.6	12 279	37.5	11 056	40.2	-10
Man.	5 217	14.8	5 967	14.9	5 196	18.2	-13
Sask.	42	36.8	61	26.8	56	26.8	-9
B.C.	5 064	28.6	3 161	25.6	7 659	15.3	142

Source: Statistics Canada Publication 57-202 1982-1983.
National Energy Board 1984.

Table 16. Gross firm and interruptible exports, 1984*

	Firm	Interruptible	Per cent Interruptible	Per cent Firm
	(kWh)			
New Brunswick	2 817 369	2 876 082	50.5	49.5
Quebec	3 081 475	8 158 624	72.6	27.4
Ontario	4 068 694	6 987 638	63.2	36.8
Manitoba	469 585	4 625 943	90.8	9.2
Saskatchewan	58 680	0	0.0	100.0
British Columbia	355 850	4 072 492	92.0	8.0
Canada	10 851 653	26 720 779	71.1	28.9

* Exchanges are excluded.

Source: National Energy Board.

Table 17. Energy sources of electricity exports by province, 1984

	Oil	Coal	Nuclear	Hydro	Other	Total
New Brunswick	24.5	9.0	35.0	-	31.5	100
Quebec	-	-	-	100.0	-	100
Ontario	-	99.0	1.0	-		100
Manitoba	-	2.0	-	98.0	-	100
Saskatchewan	-	100.0	-	-	-	100
British Columbia	-	-	-	100.0	-	100

Source: Energy, Mines and Resources Canada.

Table 18. Fuel displacement of exports

Exporting Province	Importing States	Fuel Displaced
New Brunswick	New England	Oil
Quebec	New England	Oil
	New York	Oil, coal
Ontario	New York	Oil, coal
	Michigan	Coal
	Wisconsin	Coal
Manitoba	North Dakota	Coal
	Minnesota	Coal
Saskatchewan	North Dakota	Coal
British Columbia	California	Oil, coal, gas

Source: National Energy Board.

The provincial shares of total Canadian electricity exports are shown in Table 19. Quebec and Ontario were the leading exporters in 1984, followed by British Columbia and New Brunswick.

Table 19. Provincial share of Canadian exports (per cent)

	1982	1983	1984
New Brunswick	9	14	15
Quebec	25	26	27
Ontario	33	33	27
Manitoba	15	15	12
British Columbia	18	12	19
Canada	100	100	100

Source: Energy, Mines and Resources Canada.

A summary of the forecasts by utilities, of electricity exports, is presented in Table 20. Total Canadian electricity exports are expected to continue to increase through the latter part of this decade. This increase, if it is realized, will be mostly attributable to the growth in exports from Quebec. Beyond 1990, total Canadian exports are forecast to gradually decline from 49.2 TWh in 1990 to 36.7 TWh in 2000. Manitoba is the exception to this post-1990 decline trend. Exports from Manitoba are expected to continue to increase through to the end of the century.

Table 20. Utilities' forecasts of electricity exports (TWh)

	1984 Actual	1985	1986	1990	1995	2000
New Brunswick	5.7	6.9	7.7	6.1	2.7	1.5
Quebec	11.3	13.4	19.2	22.1	17.1	15.9
Ontario	11.4	9.8	9.7	11.6	10.8	5.2
Manitoba	5.1	6.7	6.4	5.0	10.0	11.5
Saskatchewan	0.1	0.1	0.1	0.1	0.1	0.1
British Columbia	8.0	2.9	3.0	4.4	1.8	2.6
Canada	41.6	39.8	46.1	49.3	42.5	36.8

Source: Energy, Mines and Resources Canada - Utility Questionnaire.

Interprovincial Trade

The most significant changes in interprovincial transfers during 1984 were increases in net exports from Newfoundland to Quebec, where net exports increased from 31 229 GWh in 1983 to 36 043 GWh in 1984. Net exports from Quebec to Ontario increased from 5327 GWh in 1983 to 7300 GWh in 1984, up 37 per cent from the previous year. Quebec also increased its sales to New Brunswick. Net interprovincial transfers are outlined in Table 21 below. More information on exports and imports by province is provided in Figure 8 and Table A5.

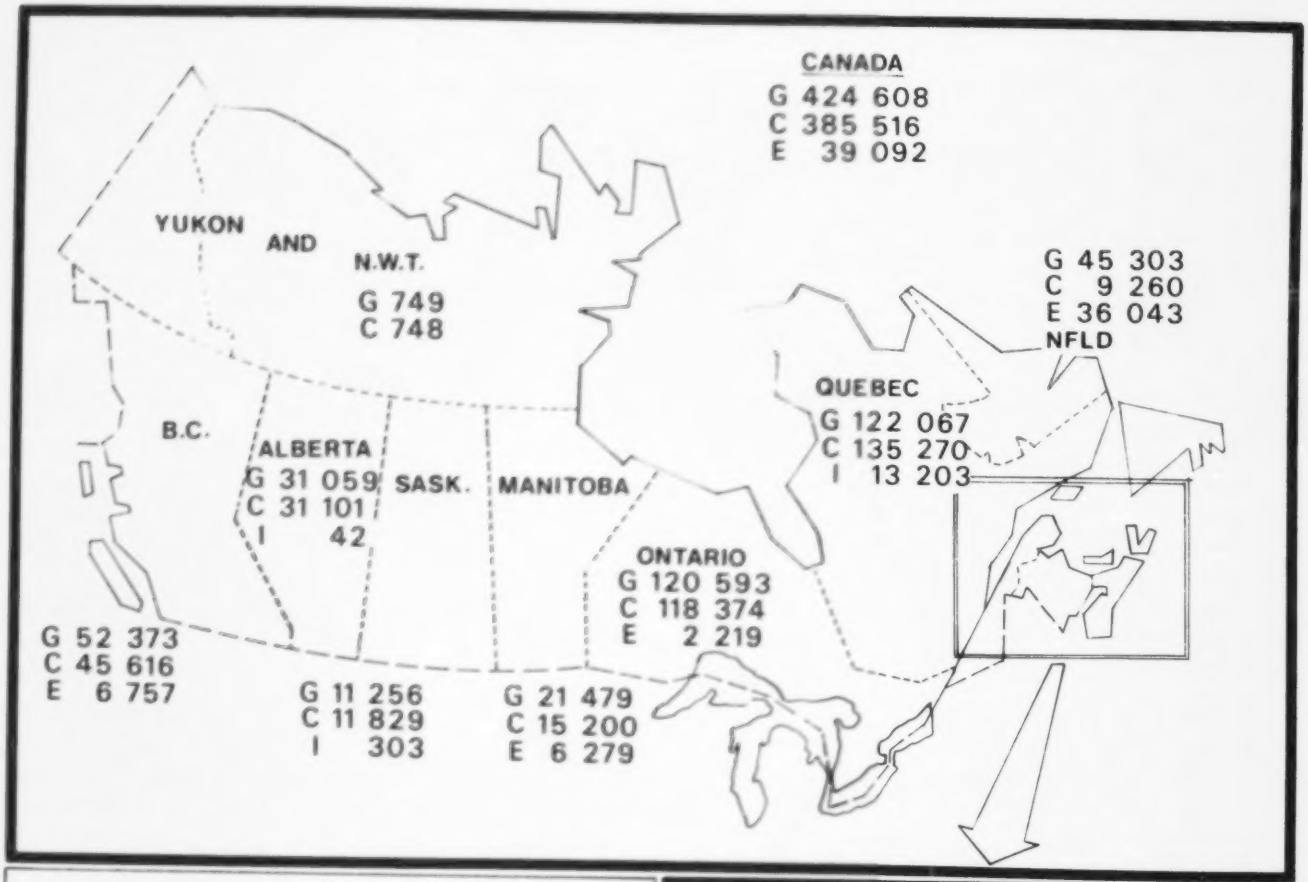
Table 21. Net interprovincial transfers (12 month period)

	GWh		
	1983	1984	% Growth
B.C. to Alta.	147.	36.	-75
Sask. to Alta.	1.	4.	300
Man. to Sask.	392.	327.	-17
Man. to Ont.	949.	937.	-1
Que. to Ont.	5 327.	7 300.	37
Nfld. to Que.	31 234.	36 043.	15
Que. to N.B.	3 988.	4 306.	8
N.B. to P.E.I.	519.	539.	4
N.B. to N.S.	600.	20.	-97

Source: Energy, Mines and Resources Canada.

FIGURE 8

NET TRANSFER AND EXPORTS OF ELECTRICAL ENERGY, 1984 (GWh)

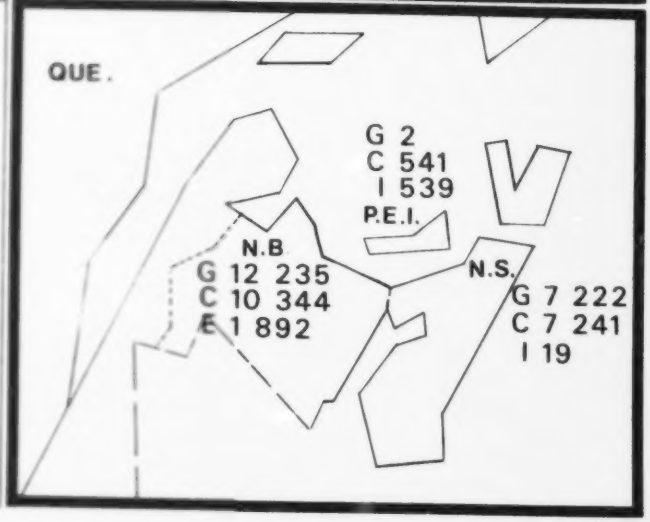


G–Generation

C–Consumption

E–Net Exports

I–Net Imports



FUEL REQUIREMENTS

Fuel Use in 1984

Table 22 provides information on fuels used by utilities in 1984. Ontario was the largest user of fuels for electricity production in 1984, accounting for approximately 57 per cent of the total. Alberta was the second largest user, accounting for 21 per cent. New Brunswick remains the largest user of oil. The energy sources of electricity generation are changing significantly. Oil and gas use is decreasing, coal and uranium use is increasing, and hydro is remaining relatively constant.

Provinces west of Quebec use Canadian oil, primarily light oil used in gas turbines or diesel plants. In the Territories, Canadian diesel oil is used to supply electricity to small remote communities. All oil used by the Atlantic region and Quebec is imported from outside Canada.

In 1984, about 75 per cent of the coal used for electricity generation in Ontario was imported from the United States, the remainder came from Western Canada. The coal used by Manitoba was imported from Saskatchewan. Alberta, Nova Scotia, and New Brunswick used their own coal resources for electricity generation. Saskatchewan relied primarily on its own coal, but also imported additional amounts from Alberta.

Nova Scotia and New Brunswick have used oil extensively for electricity generation, but new coal-fired and nuclear plants will increasingly displace oil. In 1984, the last of four remaining coal-fired units at Nova Scotia Power Lingan Plant was put in service. New Brunswick will double hydro electricity imports from Quebec by 1985. Hydroelectricity is expected to displace most of the oil-fired generation in Newfoundland, and Ontario has already displaced all of its major oil-fired generation. Alberta is the main user of natural gas for electricity generation, although this use is diminishing as coal-fired generation increases.

Forecast of Fuel Requirements

Forecast fuel requirements are reported in Table 23. These fuel requirements are based on the forecasts of energy generation indicated in Table 13.

Because of a substantial reduction in coal-fired generation in Ontario, coal consumption is expected to decrease from about 42 million tonnes in 1984 to 36 million tonnes in 1990, before gradually rising again to 53 million tonnes by the year 2000. The major increase in coal use will be in Nova Scotia and Alberta.

Oil consumption is expected to increase at a more moderate rate to 1.763 million cubic metres (or 11 million bbls) in 1990, and to 2.445 million cubic metres (or 15 million bbls) by the year 2000. Oil will be used primarily for peaking purposes and in remote locations.

Over the forecast period, the use of natural gas for electricity generation is projected to increase slightly from 1.067 to 1.445 billion cubic metres. Industrial establishments will be the largest users of natural gas for electricity generation; their share is predicted to account for 57 per cent for the forecast period 1984-2000.

Because nuclear energy is becoming increasingly important as a component of Canadian electricity supply, the use of uranium for electricity generation is expected to increase substantially from 909 tonnes in 1984 to about 1940 tonnes toward the end of the century, an average annual growth rate of 4.9 per cent.

Table 22. Fuel used by utilities, 1984

	Coal (thousand tonnes)	Oil (cubic metres)	Gas (million cubic metres)	Uranium (tonnes)
Newfoundland	-	326 103	-	-
Prince Edward Island	59	5 050	-	-
Nova Scotia	2 012	207 929	-	-
New Brunswick	601	568 000	-	108
Quebec	-	59 378	-	68
Ontario	13 618	15 711	3	733
Manitoba	156	151	1	-
Saskatchewan	7 920	5 000	141	-
Alberta	17 137	16 075	265	-
British Columbia	-	45 500	-	-
Yukon/NWT	-	165 000	-	-
Canada	41 503	1 413 897	410	909

Source: Energy, Mines and Resources Canada - Utility Questionnaire.

Table 23. Fuels required for electricity generation in Canada

	Coal (million tonnes)	Oil (million cubic metres)	Natural Gas (billion cubic metres)	Uranium (tonnes)
1985	38.0	1.8	1.2	1 313
1990	36.1	1.8	1.1	1 800
1995	42.6	2.2	1.6	2 041
2000	53.2	2.4	1.5	1 940

Source: Energy, Mines and Resources Canada - Utility Questionnaire.

Note: 1 cubic metre of oil = 6.3 bbls.
1 cubic metre of gas = 35.5 cubic feet.

TRANSMISSION

Provincial

The most extensive additions to provincial transmission lines in 1984 occurred in Quebec, where Hydro-Québec increased its in-province lines by 951 km. Alberta was the second largest builder of new transmission, with Alberta Power adding 197 km and TransAlta a further 106 km. In Manitoba, the transfer capability from the Nelson River to Southern Manitoba was increased by 500 MW. In 1985, the transfer capability will be increased by a further 500 MW. In British Columbia, transmission was increased in 1984 by the addition of three 500 kV lines.

Interprovincial

There were no additions during 1984 to provincial interconnections. Presently under construction and planned for completion in 1985 and 1986 respectively are two additional interconnections: a 130 kV line from Hydro-Québec's Madawaska substation to the substation at Edmunston, New Brunswick and a 500 kV line from Cranbrook, British Columbia to Alberta. Table 24 shows the existing interconnections, while Table 25 summarizes the proposed new additions planned for 1985-86.

International

There are now over 100 international transmission lines in place to service electricity exports to the United States. Although most of these lines are quite small, there are thirty-three bulk power interties rated at 69 kV or higher with power transfer capacity near 13 000 MW. These are outlined in Table 26.

In order to accommodate Quebec's increasing exports to the New England states, two transmission lines are under construction. One is a 120 kV line to Vermont, to be completed this year, and the other is a 450 kV direct current line to New Hampshire, to be completed in 1986. If the proposed electricity sales by Hydro-Québec to the New England Power Pool are approved by the National Energy Board, the intertie capacity between Quebec and New England will have to be strengthened from 690 to 2000 MW. The planned interconnections are outlined in Table 27.

Table 24. Provincial interconnections

Connection	Voltage	Capability	
		Installed	Firm
	(kV)	(MW)	
British Columbia - Alberta	1 x 138	110	80
Saskatchewan - Manitoba	3 x 230	400	400
Manitoba - Ontario	2 x 230	260	260
	1 x 115		
Quebec - Ontario	4 x 230	1300	1300
	9 x 120		
Quebec - Newfoundland	3 x 735	5225	4300
Quebec - New Brunswick	80(DC)	350	350
	1 x 230	150	150
	1 x 345	150	150
New Brunswick - Nova Scotia	2 x 138	600	600
	1 x 345		
New Brunswick - P.E.I.	1 x 138	200	100

Source: Energy, Mines and Resources Canada.

Table 25. Proposed provincial interconnections

Province Installed	Connections	Year	Capability	
			Installed	Firm
	(kV)		(MW)	
British Columbia - Alberta*	500 (AC)	1986	800	600
Quebec - New Brunswick*	80 (DC)	1985	350	350

* Under Construction.

Source: Energy, Mines and Resources Canada - Utility Questionnaire.

Table 26. Major interconnections between Canada and the United States*

Province	State	Voltage (kV)	Power Transfer Capability (MW)
New Brunswick	Maine	345	600
		5 x 69	330
Quebec	New York	765	1400
	New York	2 x 120	200
	Vermont	120	100
Ontario**	New York	230	470
		230	400
		2 x 230	600
		2 x 345	2300
		4 x 69	265
	Michigan	230	535
		230	515
		345	710
		345	760
	Minnesota	120	35
Manitoba	North Dakota	230	150
	Minnesota	230	175
	Minnesota	500	1000
Saskatchewan	North Dakota	230	150
British Columbia	Washington	230	350
		230	300
		2 x 500	1400

* 35 MW capacity or over.

** The transfer capability of several lines may not be equal to the mathematical sum of the individual transfer capabilities of the same lines.

Source: Energy, Mines and Resources Canada - Utility Questionnaire.

Table 27. Planned interconnections to the United States

Province	State	Completion Date	Voltage (kV)	Estimated Power Transfer Capability (MW)
Quebec	New Hampshire	1986	450 DC	690*
Quebec	Vermont	1985	120	200

* May be upgraded to 2000 MW by 1990.

CAPITAL EXPENDITURES

Capital Investment

Utility investment in new facilities was $6.4 billion in 1984, significantly less than the $7.8 billion spent in 1983. Approximately 56 per cent of the 1984 total was for generation, 18 per cent for transmission, 13 per cent for distribution, and the remainder for other items. Table 28 illustrates the capital-intensive nature of electricity supply and its importance in the Canadian economy, while Table 29 shows the original costs of utility fixed assets in service. The ratio of generation investment to total investment has increased from 52 per cent in 1979 to about 56 per cent in 1984. This investment pattern varies from one region to another, depending on the generation mix employed. The capital investment, per unit of capacity added, is significantly higher for hydro and nuclear capacity than for conventional thermal capacity. Hydro and nuclear generation are characterized by high capital costs and low operating costs, relative to a conventional thermal plant. In addition, hydro facilities often also require higher capital expenditures for transmission facilities, because of the remote location of the generating plants.

Table 30 presents capital expenditures for electrical system expansion in each province for 1984, and forecast capital expenditures for 1985 to 1994. Capital expenditures are forecast to decline until 1986, reflecting the completion of projects now underway and present excess generating capacity. After 1986 capital expenditures increase again, reaching a new peak in 1990.

The capital expenditures projected for this year show a major change from last year. Cumulative capital expenditures over the period 1985-1993 are expected to reach $63 billion. This level is considerably less than the previous year's forecast of $73 billion, reflecting the lower load growth forecasts in several provinces. An increasing emphasis will be put on upgrading transmission and distribution systems over the next few years, with relatively less emphasis on generation facilities. The historical data in Table 31 indicate that capital expenditures have increased at an average annual rate of 11.4 per cent since 1965. The average annual rate of inflation (measured by the Gross National Expenditure deflator) over this period was 7.3 per cent, indicating that real growth was approximately 4.1 per cent.

Financing

From 1960 to 1976 debt for utility expansion increased as a percentage of total capital employed. The debt ratio was relatively stable until 1978, and then declined for the period 1979-1982 as most utilities tried to reduce their exposure to high interest rates. However, the debt proportion increased again in 1983 as electric utilities increased their investment and borrowings. Table 32 shows electric utility debt ratios during the period 1976-1983. In 1976, debt accounted for 83 per cent of capitalization in provinces with predominantly provincially-owned utilities. It was 50 per cent in those provinces with predominantly investor-owned utilities. By 1983, debt decreased to 80 per cent for provincially-owned utilities, and to 46 per cent for investor-owned utilities.

In 1983, utilities used internally generated funds (mainly net income and depreciation) for about 28 per cent of capital expenditures. Internally generated funds are expected to meet about 30 - 35 per cent of capital requirements in the next five years.

Table 28. Electric utility capital investment

	1966-70	1971-75	1980	1981	1982	1983	1984
Investment in electric power ($ billions)	6.8	12.9	6.1	7.3	8.4	7.8	6.4
Energy share*(%)	55	56	42	40	42	42	39
Economy share*(%)	8	9	9	9	11	10	8
GNP share*(%)	1.9	2.0	2.1	2.2	2.5	2.0	1.5

* The figures indicate electrical utility capital investment as a percentage of total energy investment, investment in the economy as a whole, and GNP.

Source: Statistics Canada Publications 61-205 and 11-003E.

Table 29. Original cost of utility fixed assets in service

	1979		1981		1982		1983		1984	
	(millions)	(%)	(millions)	(%)	(millions)	(%)	(millions)	(%)	(millions)	(%)
Generation	19 177	52	24 943	53	28 352	54	34 203	56	38 301	56
Transmission	7 421	20	9 632	20	10 828	20	12 035	20	13 352	19
Distribution	7 950	21	9 554	20	10 650	20	11 836	19	12 787	19
Other	2 601	7	3 145	7	3 031	6	3 409	5	4 360	6
Total	37 149	100	47 274	100	52 861	100	61 483	100	68 800	100

Source: Statistics Canada Publication 57-202
Data for 1984 preliminary

Table 30. Capital expenditures by electric utilities

	(Millions of Current Dollars)										
	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
Newfoundland	135	75	72	201	806	1498	1758	1437	1152	571	400
Prince Edward Island	5	7	11	12	6	6	7	8	9	10	10
Nova Scotia	130	57	74	86	65	147	308	383	301	277	277
New Brunswick	136	55	66	94	98	99	82	71	74	75	88
Quebec	1681	1784	1939	1967	1994	2065	1730	1810	1940	2076	2526
Ontario	2842	2833	2538	2476	2280	1953	2094	2030	1 807	1 877	1 890
Manitoba	125	255	313	503	516	517	560	426	453	388	931
Saskatchewan	256	264	190	250	377	440	422	364	371	431	533
Alberta	656	656	615	661	617	702	913	790	788	801	833
British Columbia	448	217	124	116	145	185	230	213	202	234	294
Yukon, NWT	30	6	6	17	5	13	2	4	4	7	8
Canada	6426	6209	5948	6383	6909	7625	8106	7536	7 101	6 747	7 790

Source: Energy, Mines and Resources - Utility Questionnaire
Fiscal and calendar years combined
Data for 1984 is preliminary

Table 31. Historical electric utility investment

Year	Construction			Sub-Total	Machinery and Equipment	Total
	Generation	Transmission and Distribution*	Other			
	(millions of current dollars)					
1965	438	277	12	727	212	939
1966	493	281	13	787	356	1413
1967	577	262	36	875	390	1265
1968	533	301	54	889	443	1332
1969	511	281	63	856	546	1403
1970	581	449	28	1057	554	1610
1971	572	472	36	1079	668	1747
1972	636	449	50	1135	619	1754
1973	808	539	69	1417	827	2244
1974	1049	598	53	1700	1054	2753
1975	1691	874	96	2661	1296	3957
1976	1803	821	30	2654	1574	4229
1977	2205	911	43	3158	1726	4884
1978	2339	1199	233	3761	2175	5936
1979	2516	1424	181	4121	2243	6364
1980	2470	1433	95	3998	2111	6109
1981	2768	1554	92	4414	2905	7319
1982	3153	1818	320	5322	3086	8408
1983	2663	1755	202	4620	3150	7770
1984(a)	-	-	-	3207	3219	6426

* Transmission and distribution includes street lighting. Generation includes transformer stations, dams and reservoirs.

(a) Preliminary actual data, no breakdown available.

Note: The totals may not correspond with the sum of the elements due to rounding.

Source: Statistics Canada Publications 57-202, 61-205, and Canada Year Book 1968-79.

Table 32. Electric utility debt ratio

	1976	1977	1978	1979	1980	1981	1982	1983
				(%)				
Newfoundland	79	76	76	76	74	71	73	78
Prince Edward Island	53	53	52	53	54	55	55	68
Nova Scotia	103	102	99	98	95	97	97	96
New Brunswick	92	92	93	93	91	91	90	89
Quebec	76	76	76	75	75	75	75	75
Ontario	77	77	78	78	78	78	80	79
Manitoba	97	97	96	94	94	95	96	96
Saskatchewan	73	77	78	78	80	85	89	92
Alberta	49	47	44	45	42	42	49	70
British Columbia	94	95	94	86	85	85	85	86
Yukon and Northwest Territories	102	99	98	98	98	99	98	96
Canada	80	80	80	78	77	77	78	80

Debt ratio = debt/(debt + equity).
Debt: Long-term + short-term loans and notes payable.
Equity: Total of capital, reserves, and surplus.

Source: Statistics Canada Publication 57-202.

COSTING AND PRICING

Electricity Supply Costs

The unit cost of supplying additional electricity increased rapidly during the period 1973-1982. However, cost increases have moderated significantly since then; adjusted for inflation, the real increases in the cost of electricity have been small. This is expected to be the case for the next several years.

In the 1973-1982 period, there were two basic reasons for the rapid increases in the cost of electricity: the high rate of inflation and the increased cost of fossil fuels. High levels of inflation affect the electric utility industry in two ways, by increasing the capital cost of constructing additional facilities and by increasing the cost of borrowed funds.

The average interest rate on new long-term utility debt for the period 1968-1984 is shown in Figure 9. Interest rates started to rise in 1973, reached a peak in 1981 and 1982, and then dropped substantially in 1983. The index of electric utility construction costs is presented in Figure 10. It shows the significant increase in utility construction costs between 1973 and the present, a trend shared by most capital projects. In general, electricity construction costs tend to parallel the Consumer Price Index.

The increases in fossil fuel costs experienced since 1969 are summarized in Figure 11. It is clear from Figure 11 that fuel costs for electricity generation were generally stable prior to the oil crisis of 1973, and that they began to rise thereafter. For Canada as a whole, the fuel cost per kWh generated from fossil fuels increased more than four fold between 1973 and 1983, from 3.1 mills to 13.2 mills. The increase in the cost of fuel from oil generation was much more dramatic, growing from 7.1 mills to 57.3 mills per kWh during the same period, an average annual increase of 23 per cent. The impact of the cost increase varies between regions of the country and depends on the type of fuel used, its source, and the percentage of total energy supply derived from fossil fuel plants.

Pricing

The average revenue from electricity sales for each province is provided in Table 33. Because electricity rates are regulated to cover costs, the average revenue per unit of electricity started to increase substantially in 1975, with the escalation in the cost of electricity generation. The average annual growth in the unit revenue for Canada as a whole was 13 per cent during the period 1974-1983. The national inflation rate, as measured by the Consumer Price Index (CPI), was 9.3 per cent over the same period.

Costs increased more rapidly in some regions than others, because of differences in generation mix, fuels used, and rates of system expansion to meet increased demands for electricity. Table 34 gives monthly electricity costs for selected Canadian cities. Table 35 details the average annual rate increases for customers in each province since 1976.

Figure 12 illustrates the movements of the electricity and oil/gas components of the CPI, and the movement of the Energy Price Index, as well as the CPI itself. It indicates that the electricity price component increased more slowly than, or equal to, the rate of increase of the CPI for the period 1971-1976. Since 1977, the electricity price has been consistantly greater than the CPI; however, it has increased significantly more slowly than the oil and gas price indices.

FIGURE 9

AVERAGE INTEREST RATE ON PUBLIC UTILITY NEW LONG-TERM DEBT

1960-1984

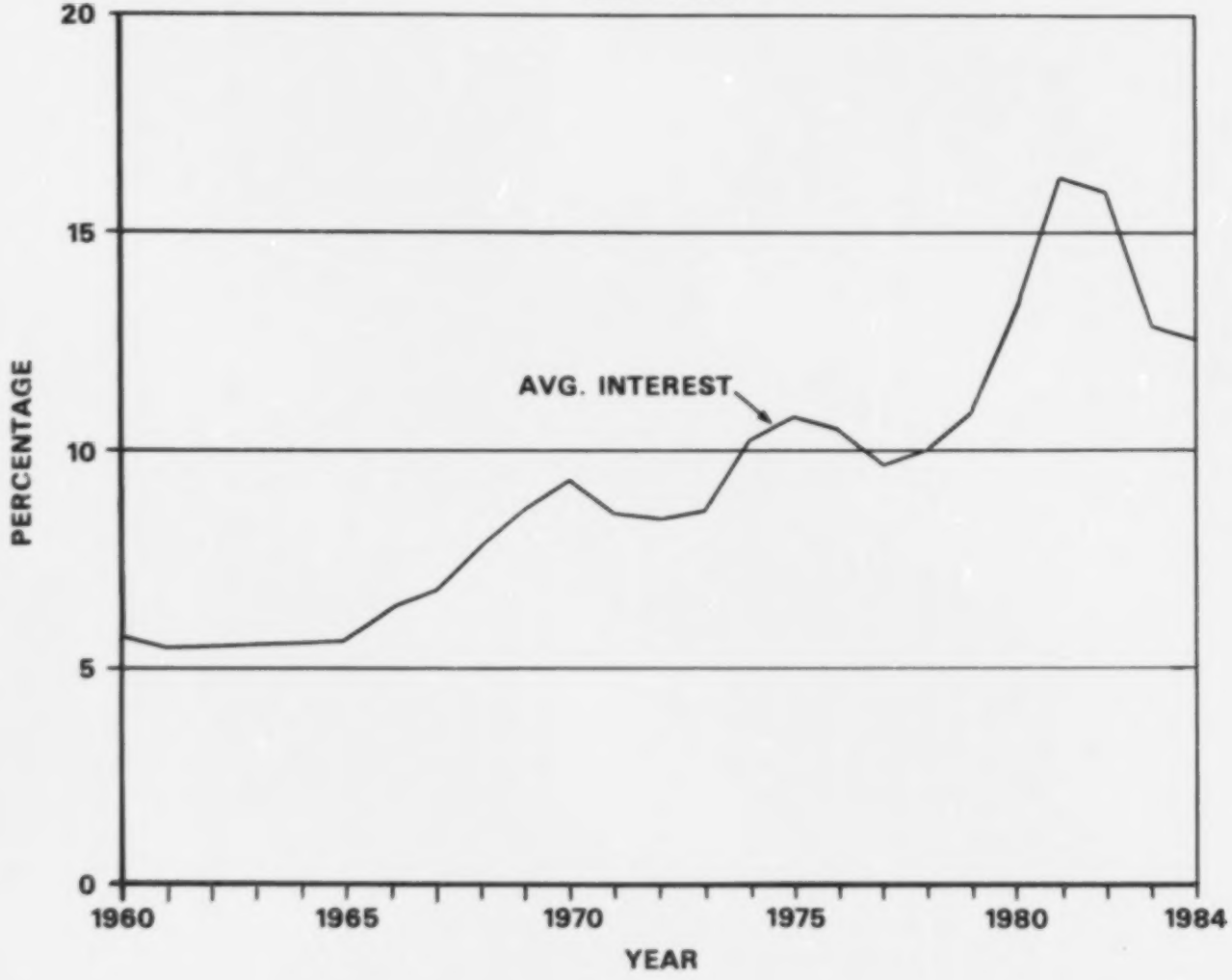


FIGURE 10

PRICE INDEX TRENDS IN UTILITY CONSTRUCTION

1968-1984

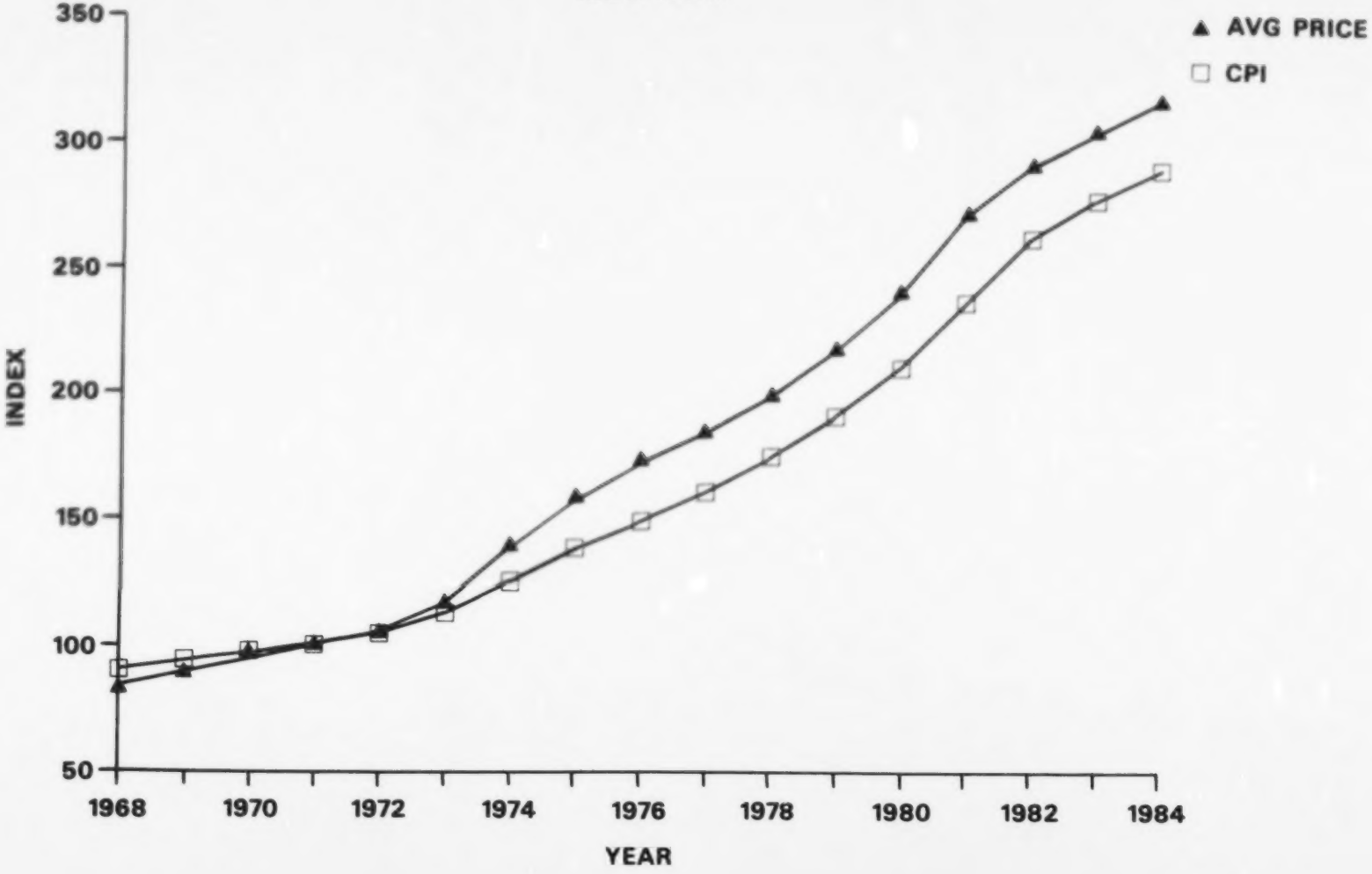


FIGURE 11

UNIT COST OF FOSSIL FUEL FOR ELECTRICITY PRODUCTION
1969-1983

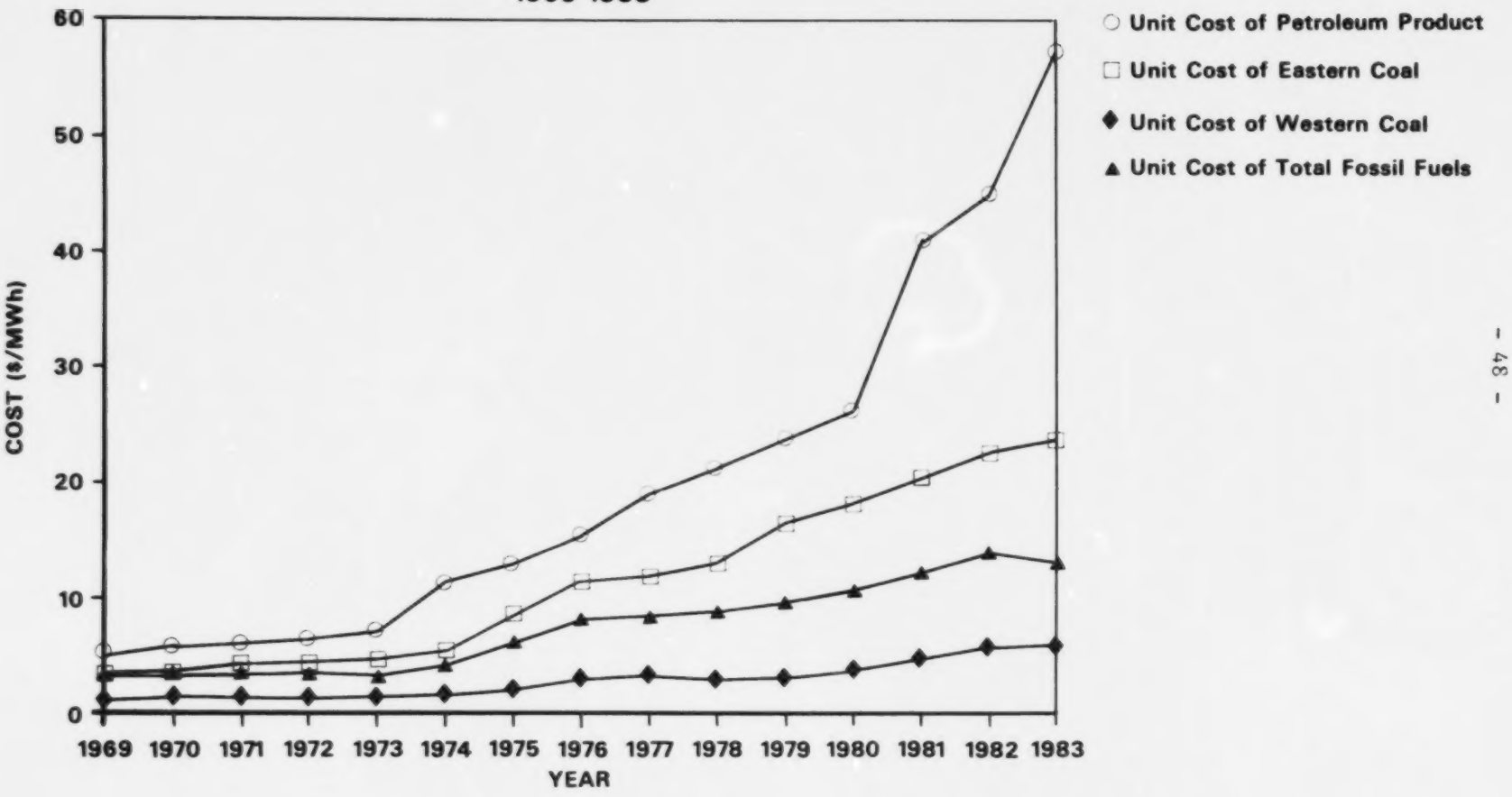


Table 33. Average revenue from electricity sales by province

	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983
	(current cents/kWh)									
Newfoundland	1.3	1.4	1.4	1.7	2.0	2.2	2.3	2.8	3.6	3.7
Prince Edward Island	3.7	4.1	5.1	5.9	6.4	7.2	8.1	10.0	12.0	12.4
Nova Scotia	2.0	2.5	2.8	3.9	4.4	4.6	4.5	4.9	5.9	6.9
New Brunswick	1.6	1.9	2.0	2.4	3.2	3.7	4.1	4.8	5.1	5.3
Quebec	1.1	1.3	1.4	1.5	1.7	2.0	2.2	2.6	3.1	3.3
Ontario	1.4	1.6	1.8	2.3	2.4	2.6	2.9	3.2	3.6	3.9
Manitoba	1.2	1.4	1.7	1.9	2.3	2.7	2.8	2.8	2.9	3.0
Saskatchewan	1.6	1.8	2.1	2.4	2.7	2.7	2.9	3.6	4.0	4.2
Alberta	1.7	2.0	2.4	2.7	3.1	3.2	3.4	4.1	4.9	5.2
British Columbia	1.4	1.6	1.8	2.1	2.2	2.4	2.6	3.0	3.8	3.8
Yukon	2.6	2.7	3.5	4.1	4.4	4.9	5.3	6.7	8.3	8.6
Northwest Territories	3.6	4.0	5.2	6.9	7.7	9.0	10.0	11.5	14.8	18.0
Canada	1.3	1.5	1.7	2.0	2.3	2.5	2.8	3.1	3.7	3.9

Source: Statistics Canada Publication 57-202

Table 34. Monthly electricity costs for selected Canadian cities, January 1984

Sector	Residential	Commercial	Industrial
Billing Demand (KW)	-	100	1000
Consumption (KWh)	1000	25 000	400 000
	($)		
St. John's	64.73	1 656.25	20 358.62
Charlottetown	116.62	3 368.94	43 745.12
Halifax	65.22	2 027.21	21 104.61
Moncton	57.43	1 865.70	18 450.00
Montreal	37.07	1 261.00	14 719.50
Ottawa	42.45	1 117.85	15 952.85
Toronto	46.90	1 467.90	17 568.00
Winnipeg	33.78	892.87	10 141.70
Regina	41.40	1 384.15	16 859.17
Calgary	49.65	1 445.54	16 670.62
Edmonton	46.00	1 367.60	17 755.59
Vancouver	48.26	1 206.05	14 517.56
Whitehorse	66.30	2 130.00	-
Yellowknife	95.00	3 255.00	48 605.00

Source: Statistics Canada Publication 57-203.

Table 35. Average annual rate increases, 1976-1984

Utility	Rate Changes (%): Average of all Customer Classes								
	1976	1977	1978	1979	1980	1981	1982	1983	1984
Newfoundland Hydro	14.0	8.4	25.0	-	19.0	15.8	-	18.2	-
Newfoundland Light & Power	13.4	9.8	21.2	12.4	11.8	14.6	-	12.0	-
Maritime Electric	(8.0)	17.0	13.0	-	13.1	21.4	-**	-	-
Nova Scotia Power	-	43.0	14.0	12.5	-(2)	-	-	36.6	-
New Brunswick Power	12.0	16.6	9.9	7.9	7.8	9.8	-	8.8	6.2
Hydro-Québec	10.3	9.9	18.7	13.7	13.3	10.6	16.3	7.3	4.0
Ontario Hydro	14.9	25.6	5.7	7.7	7.3	10.0	10.0	8.2	7.5
Manitoba Hydro	16.6	15.0	14.9	14.4	-(1)	-	-	9.5	7.9
Saskatchewan Power	13.0	17.0	3.3	8.3	7.9	16.1	-	12.6	9.2
Edmonton Power	10.1	6.0	8.1	-	26.0	12.0	13.2	8.0	5.0
TransAlta Utilities	25.8	14.7	15.6	7.5	-	13.0	4.0	15.0	-
Alberta Power	11.4	20.2	-	-	12.3	28.9	-11.6*	-	-
B.C. Hydro	14.2	12.1	13.4	5.5	7.6	2.6	20.0*	6.0	6.5

(1) The provincial government froze rates from 1979 until 1983.

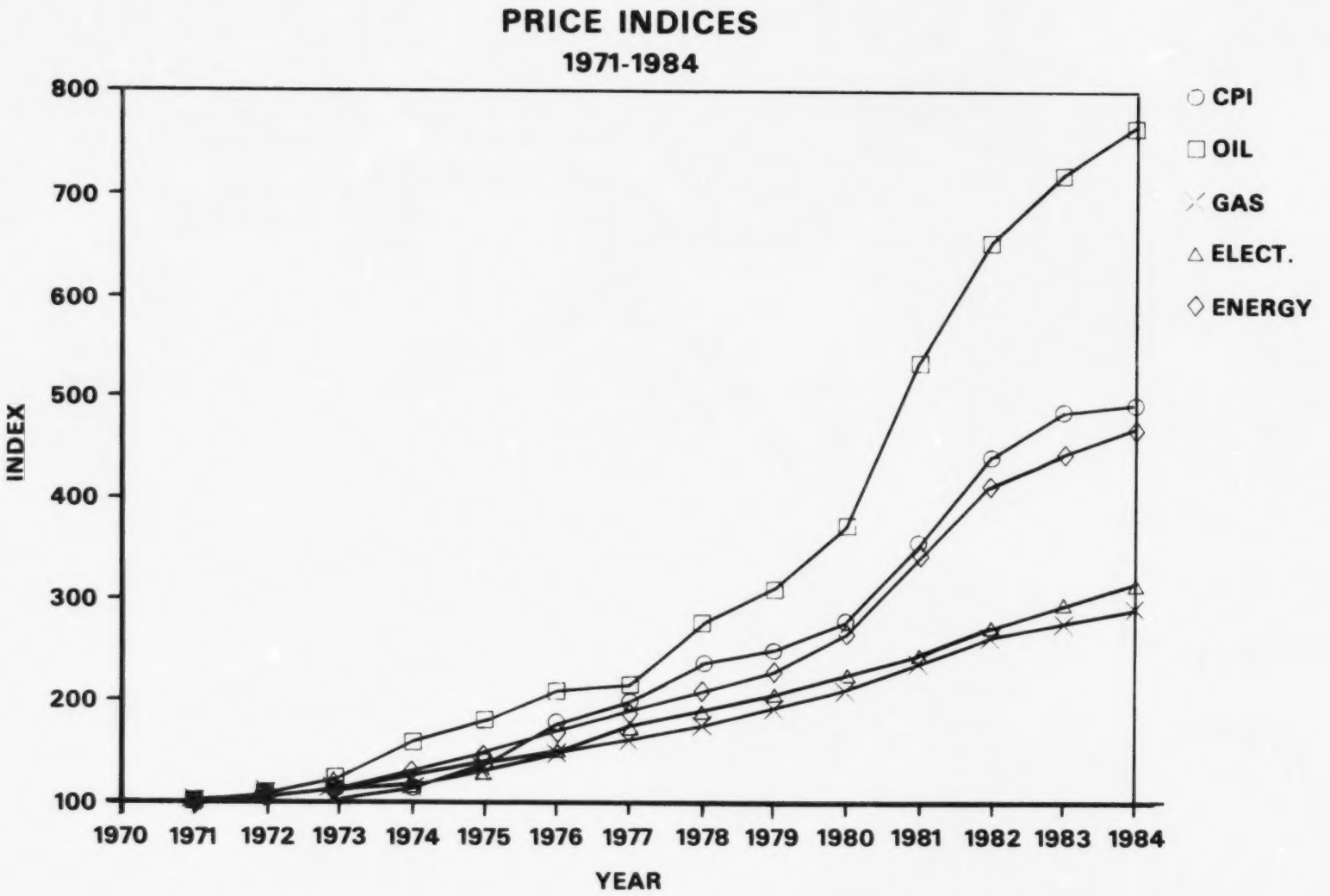
(2) The provincial government froze rates in 1980.

* Based on residential category. Reduction in rates is a result of Alberta Electric Energy Marketing Agency rebate.

** Does not reflect monthly changes to the cost of commodity and fuel adjustment charges.

Source: Energy, Mines and Resources

FIGURE 12


PRICE INDICES
1971-1984
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INDEX
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1980
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1984
YEAR
CPI
OIL
GAS
ELECT.
ENERGY

Appendices

A1. Installed capacity and electrical energy consumption in Canada, 1920-1984

A2. Installed and proposed generating capacity, 1984

A3. Conventional thermal capacity by principal fuel type

A4. Electrical energy production by principal fuel type

A5. Provincial electricity imports and exports

A6. Generation capacity by type and province

A7. Installed generating capacity expansion in Canada by station. Major additions in 1984 and projections 1985-2004.

Table A1. Installed capacity and electrical energy consumption in Canada, 1920-1984

Year	Installed Capacity					Electrical Energy Consumption(a)	Average Demand(b)	Peak Demand(c)	Reserve Margin(d)		Load Factor(e)
	Thermal										
	Conventional	Nuclear	Sub-Total	Hydro	Total						
	(MW)					(GWh)	(MW)	(MW)	(MW)	%	%
1920	300	-	300	1 700	2 000	-	-	-	-	-	-
1930	400	-	400	4 300	4 700	19 468	2 222	-	-	-	-
1940	500	-	500	6 200	6 700	33 062	3 774	-	-	-	-
1950	900	-	900	8 900	9 800	55 037	6 283	-	-	-	-
1955	2 100	-	2 100	12 600	14 700	81 000	9 247	12 536	2 164	17	74
1960	4 392	-	4 392	18 657	23 049	109 302	12 477	17 264	5 785	34	72
1961	5 072	-	5 072	19 019	24 091	110 950	12 666	18 353	5 738	31	69
1962	5 609	20	5 629	19 338	24 967	116 135	13 257	18 937	6 030	32	70
1963	6 180	20	6 200	20 101	26 301	121 510	13 871	20 783	5 518	27	67
1964	6 694	20	6 714	20 313	27 027	133 949	15 291	22 516	4 511	20	68
1965	7 557	20	7 577	21 771	29 348	144 165	16 457	24 167	5 181	21	68
1966	8 307	20	8 327	22 438	30 765	156 956	17 917	25 921	4 844	19	69
1967	9 373	240	9 613	23 353	32 966	165 812	18 928	27 812	5 154	19	68
1968	10 711	240	10 951	24 957	35 908	176 841	20 187	30 300	5 608	19	67
1969	12 321	240	12 561	27 031	39 592	189 522	21 635	32 092	7 500	23	67
1970	14 287	240	14 527	28 298	42 826	202 337	23 098	34 592	8 234	24	67
1971	14 504	1 570	16 075	30 601	46 676	212 882	24 302	35 720	10 956	31	68
1972	15 318	2 126	17 444	32 500	49 944	231 557	26 433	38 921	11 023	28	68
1973	17 711	2 400	20 111	34 266	54 376	249 298	28 459	42 699	11 677	27	67
1974	18 085	2 666	20 751	36 779	57 530	266 956	30 747	42 528	15 002	35	72
1975	21 404	2 666	24 070	37 282	61 352	265 955	30 360	46 187	15 165	33	66
1976	23 039	3 466	26 505	39 488	65 993	284 829	32 515	49 537	16 456	33	66
1977	24 699	5 066	29 765	40 810	70 575	299 673	34 209	52 001	18 574	36	66
1978	26 154	5 866	32 020	41 898	73 918	316 435	36 123	54 106	19 812	37	67
1979	27 353	5 866	33 219	44 009	77 228	323 465	36 925	55 699	21 529	39	66
1980	27 853	5 866	33 719	47 919	81 634	340 069	38 821	59 170	22 464	38	66
1981	28 493	5 600	34 093	49 216	83 308	346 333	39 536	59 237	24 071	41	67
1982	28 957	6 547	35 504	50 007	85 511	345 115	39 397	62 417	23 094	37	63
1983r	30 748	7 505	38 253	51 274	89 527	359 764	41 077	66 866	22 626	34	61
1984*	31 068	9 587	40 645	54 875	95 530	385 516	44 009	69 044	26 486	38	64

(a) 1920-55: Figures are approximate, computed using actual Statistics Canada data for stations generating energy for sale to which have been added estimates for stations generating entirely for own use. 1920-55: Canadian Energy Prospects (Royal Commission on Canada's Economic Prospects) John Davis, 1957. 1956-81, Statistics Canada Publication. 57-202.

(b) Average Demand = Energy Consumption ÷ 8 760 (hrs/yr) (c) Statistics Canada Publication 57-204

(d) Reserve margin = $\frac{\text{(Installed capacity - Peak demand)}}{\text{Peak demand}}$ (e) Load Factor = Average demand ÷ Peak demand

* Preliminary data r - Revised figures.

Table A2. Installed and proposed generating capacity, 1984 (MW)

	Hydro	Nuclear	Conventional Thermal*	Total	% of Canadian Total
Newfoundland	6 215	0	752	6 967	7.29
Prince Edward Island	0	0	122	122	.13
Nova Scotia	386	0	1 982	2 368	2.48
New Brunswick	901	680	1 904	3 485	3.65
Quebec	24 762	951	1 119	26 832	28.09
Ontario	7 131	7 956	13 672	28 759	30.10
Manitoba	3 641	0	501	4 142	4.34
Saskatchewan	576	0	2 074	2 650	2.77
Alberta	734	0	6 893	7 627	7.98
British Columbia	10 379	0	1 867	12 246	12.82
Yukon	102	0	40	142	.15
Northwest Territories	49	0	142	191	.20
Canada Total At Dec. 31, 1984**	54 876	9 587	31 068	95 531	100.00
Percent of Total Capacity, End 1984	57.44	10.04	32.52	100	-
Net Additions During 1984**	3 601	1 813	623	6 037	-
Planned Additions During 1985	1 640	462	1 300	3 402	-

* Details provided in Table A3. Conventional thermal includes steam, gas turbine, internal combustion.

** Preliminary Data.

Source: Energy, Mines and Resources - Utility Questionnaire

Table A3. Conventional thermal capacity by principal fuel type. Preliminary figures as at December 31, 1984 (MW)

	Steam					Gas Turbine			Internal Combustion			All Conventional Thermal				
	Coal	Oil	Gas	Other*	Total	Oil	Gas	Total	Oil	Gas	Total	Coal	Oil	Gas	Other*	Total
Newfoundland	-	503	-	-	503	170	-	170	79	-	79	-	752	-	-	752
Prince Edward Island	-	71	-	-	71	41	-	41	11	-	11	-	122	-	-	122
Nova Scotia	946	831	-	-	1 777	205	-	205	1	-	1	946	1037	-	-	1 982
New Brunswick	285	1 551	-	40	1 876	23	-	23	5	-	5	285	1 579	-	40	1 904
Quebec	-	630	-	10	640	363	-	363	116	-	116	-	1 110	-	10	1 119
Ontario	10 35	2 298	165	86	12 899	581	181	762	4	6	10	10 350	2 883	352	86	13 671
Manitoba	419	-	4	23	446	24	-	24	32	-	32	419	55	4	23	501
Saskatchewan	1 772	-	106	43	1 922	-	146	146	7	-	7	1 772	7	252	43	2 074
Alberta	4 873	66	1 279	107	6 325	-	524	524	14	30	44	4 873	80	1 833	107	6 893
British Columbia	-	124	1 038	256	1 419	185	154	339	91	18	109	-	400	1 210	256	1 867
Yukon	-	-	-	-	-	-	-	-	40	-	40	-	40	-	-	40
NWT	-	-	-	-	-	-	-	-	141	-	141	-	141	-	-	141
Canada	18 645	6 073	2 592	564	27 876	1 592	1 005	2 598	540	54	595	18 645	8 206	3 652	564	31 068

* Mainly wood wastes and black liquor.

Source: Energy, Mines and Resources - Utility Questionnaire

Table A4. Electrical energy production by principal fuel type 1984 (GWh)

	Conventional Thermal								% of Total	% Generated By	
	Coal	Oil	Gas*	Sub-Total	Nuclear	Hydro	Other	Total	Generation	Utilities	Industry
Newfoundland	0	781	0	781	0	44 522	0	45 303	10.7	98.9	1.1
Prince Edward Island	141	2	0	132	0	0	0	143	0.0	100.0	0.0
Nova Scotia	2 952	3 239	0	6 191	0	1 031	0	7 222	1.7	95.1	4.9
New Brunswick	477	3 426	0	3 903	5 011	3 093	87	12 094	2.8	94.3	5.6
Quebec	0	141	0	141	3 422	118 504	1	122 067	28.7	85.2	14.7
Ontario	33 339	366	979	38 684	40 833	40 836	240	120 593	28.5	96.8	3.1
Manitoba	211	28	2	241	0	21 226	12	21 479	5.1	99.7	0.3
Saskatchewan	9 097	34	482	9 613	0	1 705	208	11 526	2.7	96.8	3.1
Alberta	27 747	99	1 326	29 172	0	1 427	460	31 059	7.3	91.5	8.5
British Columbia	0	456	1 381	1 837	0	50 244	292	52 373	12.3	78.7	21.3
Yukon/NWT	0	198	0	198	0	550	0	748	0.2	100.0	.0
Canada	77 964	8 770	4 170	90 904	49 266	283 138	1 300	424 608	100.0	91.1	8.9

* Estimated values

Source: Statistics Canada

Table A5. Provincial electricity imports and exports (GWh)

	Interprovincial Trade			International Trade			
	Year	Exports	Imports	Net Exports	Exports	Imports	Net Exports	Total Net Exports
Newfoundland	1984	36 043	-	36 043				36 043
	1983r	31 229	-	31 229	-	-	-	31 229
	1982	35 777	-	35 777	-	-	-	35 777
Prince Edward Island	1984	-	539	-539	-	-	-	-539
	1983	-	519	-519	-	-	-	-519
	1982	-	476	-476	-	-	-	-476
Nova Scotia	1984	282	301	-19				-19
	1983r	121	737	-616	-	-	-	-616
	1982	133	216	-83	-	-	-	-83
New Brunswick	1984	840	4 588	-3 748	5 657	17	5 640	1 892
	1983r	1 258	4 092	-2 834	5 312	70	5 242	2 408
	1982	692	3 746	-3 054	3 029	71	2 958	-96
Quebec	1984	11 668	36 113	-24 445	11 250	8	11 242	-13 203
	1983r	9 349	31 281	-21 932	10 228	9	10 219	-11 713
	1982	9 386	35 833	-26 447	8 530	7	8 523	-17 924
Ontario	1984	64	8 302	-8 238	11 370	913	10 457	2 219
	1983r	64	6 333	-6 269	12 657	469	12 188	5 919
	1982	60	6 845	-6 785	11 168	403	10 765	3 980
Manitoba	1984	2 565	1 300	1 265	5 057	43	5 014	6 279
	1983r	2 565	1 222	1 343	5 994	19	5 975	7 318
	1982	2 460	1 088	1 372	5 255	214	5 041	6 413
Saskatchewan	1984	1 302	1 625	-323	86	66	20	-303
	1983r	1 211	1 610	-399	81	84	-3	-402
	1982	1 087	1 388	-301	60	31	29	-272
Alberta	1984	262	302	-40	-	2	-2	-42
	1983r	46	166	-120	-	2	-2	-122
	1982	189	447	-258	-	2	-2	-260

Table A5. Provincial electricity imports and exports (GWh) (Cont'd)

		Interprovincial Trade			International Trade			
	Year	Exports	Imports	Net Exports	Exports	Imports	Net Exports	Total Net Exports
British Columbia	1984	298	262	36	8 015	1 294	6 721	6 757
	1983r	163	46	117	4 708	2 242	2 466	2 583
	1982	444	189	255	6 171	2 119	4 052	4 307
Yukon	1984	-	-	-	-	-	-	-
	1983	-	-	-	-	-	-	-
	1982	-	-	-	-	-	-	-
Northwest Territories	1984	-	-	-	-	-	-	-
	1983	-	-	-	-	-	-	-
	1982	-	-	-	-	-	-	-
Canada	1984				41 435	2 343*	39 092	39 092
	1983r	-	-	-	38 980	2 895*	36 085	36 085
	1982	-	-	-	34 213	2 847*	31 366	31 366

r Revised
* Includes exchanges

Source: Statistics Canada

Table A6. Generation capacity by type (MW)

	Steam	Gas Turbine	Internal Combustion	Nuclear	Total Thermal	Hydro	Total
NEWFOUNDLAND							
Total End 1983	502.60	170.39	78.75	-	751.74	6 212.70	6 964.44
Additions 1984	-	-	-	-		2.28	2.28
Total End 1984	502.60	170.39	78.75	-	751.74	6 214.98	6 966.72
Additions Proposed							
1985	-	-	-	-	-	5.51	5.51
1986	-	-	-	-	-	127.00	127.00
Total End 1986	502.60	170.39	78.75	-	751.74	6 342.59	7 094.33
PRINCE EDWARD ISLAND							
Total End 1983	70.50	40.85	11.14	-	122.49	-	122.49
Additions 1984	-	-	-	-	-	-	-
Total End 1984	70.50	40.85	11.14	-	122.49	-	122.49
NOVA SCOTIA							
Total End 1983	1 626.88	205.00	0.60	-	1 832.48	366.40	2 198.88
Additions 1984	150.00	-	-	-	150.00	20.00	170.00
Total End 1984	1 776.88	205.00	0.60	-	1 982.48	386.40	2 368.88
Additions Proposed							
1985	150.00	-	-	-	150.00		150.00
1986	-	-	-	-	-	7.30	7.30
1991	300.00	-	-	-	300.00	-	300.00
Total End 1991	2 226.88	205.00	0.60	-	2 432.48	393.70	2 826.18
NEW BRUNSWICK							
Total End 1983	1 876.08	23.38	4.84	680.00	2 584.30	901.03	3 485.33
Additions 1984	-	-	-	-	-	-	-
Total End 1984	1 876.08	23.38	4.84	680.00	2 584.30	901.03	3 485.33

Table A6. Generation capacity by type (MW) (Cont'd)

	Steam	Gas Turbine	Internal Combustion	Nuclear	Total Thermal	Hydro	Total
QUEBEC							
Total End 1983	639.75	362.88	114.45	951.40	2 068.48	22 585.02	24 653.50
Additions 1984	-	-	2.02		2.02	2 176.48	2 176.48
Total End 1984	639.75	362.88	116.47	951.40	2 070.50	24 761.50	26 829.98
Additions Proposed							
1985	-	-	-	-	-	883.50	883.50
1986	-	-	-	-	-	-	-
1987	-	-	-	-	-	21.00	21.00
1988	-	-	-	-	-	-	-
1989	-	-	-	-	-	988.00	988.34
1990	-	-	-	-	-	-	-
1991	-	-	-	-	-		-
1992	-	-	-	-	-	633.00	633.00
1993	-	-	-	-	-	734.00	734.00
1994	-	-	-	-	-	736.17	736.17
Total End 1994	639.75	362.88	116.47	951.40	2 070.50	28 757.17	30 827.67
ONTARIO							
Total End 1983	12 897.73	729.59	10.02	6 140.00	19 777.34	7 131.20	26 908.54
Additions 1984	-	33.00	2.02	1 816.00	1 851.02		1 851.02
Total End 1984	12 897.73	762.59	12.04	7 956.00	21 628.36	7 131.20	28 759.58
Additions Proposed							
1985	206.00	104.00	-	1 300.00	1 610.00	-	1 610.00
1986	-	-	-	784.00	784.00	-	784.00
1987	-	-	-	784.00	784.00	-	784.00
1988	-	-	-	881.00	881.00	-	881.00
1989	-	-	-	881.00	881.00	-	881.00
1990	-	-	-			-	-
1991	-	-	-	881.00	881.00	-	881.00
1992	-	-	-	881.00	881.00	-	881.00
Total End 1992	13 103.73	866.59	12.04	14 348.00	28 330.36	7 131.20	35 461.56

Table A6. Generation capacity by type (MW) (Cont'd)

	Steam	Gas Turbine	Internal Combustion	Nuclear	Total Thermal	Hydro	Total
MANITOBA							
Total End 1983	445.80	23.80	31.63	-	501.23	3 641.10	4 142.33
Additions 1984	-	-	-	-	-	-	-
Total End 1984	445.80	23.80	31.63	-	501.23	3 641.10	4 142.33
Additions Proposed							
1990	-	-	-	-	-	256.00	256.00
1991	-	-	-	-	-	640.00	640.00
1992	-	-	-	-	-	384.00	384.00
1996	-	-	-	-	-	87.50	87.50
1997	-	-	-	-	-	262.50	262.50
1998	-	-	-	-	-		
1999	-	-	-	-	-	130.00	130.00
2000	-	-	-	-	-	520.00	520.00
2001	-	-	-	-	-	650.00	650.00
Total End 2001	445.80	23.80	31.63	-	501.23	6 571.10	7 072.33
SASKATCHEWAN							
Total End 1983	1 921.76	103.92	6.75	-	2 032.43	575.50	2 607.93
Additions 1984		42.00	-	-	42.00	-	42.00
Total End 1984	1 921.76	145.92	6.75	-	2 074.43	575.50	2 649.93
Additions Proposed							
1985	-	-	-	-	-	168.00	168.00
1986	-	-	-	-	-	84.00	84.00
Total End 1986	1 921.76	145.92	6.75	-	2 074.43	827.50	2 901.93

Table A6. Generation capacity by type (MW) (Cont'd)

	Steam	Gas Turbine	Internal Combustion	Nuclear	Total Thermal	Hydro	Total
ALBERTA							
Total End 1983	5 930.91	524.10	44.26	-	6 499.27	733.70	7 232.97
Additions 1984	394.00	-	-	-	394.00	-	394.00
Total End 1984	6 324.91	524.10	44.26	-	6 893.27	733.70	7 626.97
Additions Proposed							
1985	-	-	-	-	-	-	-
1986	380.00	-	-	-	380.00	-	380.00
1987	-	-	-	-	.00	5.00	5.00
1988	400.00	-	-	-	400.00	-	400.00
1989	400.00	-	-	-	400.00	-	400.00
1990	380.00	-	-	-	380.00	-	380.00
1992	750.00	-	-	-	750.00	-	750.00
1993	750.00	-	-	-	750.00	-	750.00
1994	-	-	-	-	-	-	-
1995	-	-	-	-	-	-	-
1996	375.00	-	-	-	375.00	759.00	1 134.00
1997	375.00	-	-	-	375.00	906.00	1 281.00
1998	-	-	-	-	.00	151.00	151.00
1999	375.00	-	-	-	375.00	-	375.00
2000	750.00	-	-	-	750.00	-	750.00
2001		100.00	-	-	100.00		100.00
2002	-	200.00	-	-	200.00	-	200.00
2003	750.00		-	-	750.00	-	750.00
2004		100.00	-	-	100.00	-	100.00
Total End 2004	12 009.91	924.10	44.26	-	12 978.27	2 554.70	15 532.97

Table A6. Generation capacity by type (MW) (Cont'd)

	Steam	Gas Turbine	Internal Combustion	Nuclear	Total Thermal	Hydro	Total
BRITISH COLUMBIA							
Total End 1983	1 418.89	339.20	108.94	-	1 867.03	8 996.54	10 863.57
Additions 1984	-	-	-	-	-	1 382.00	1 382.00
Total End 1984	1 418.89	339.20	108.94	-	1 867.03	10 378.54	12 245.57
Additions Proposed							
1985	-	-	-	-	-	460.75	460.75
2000	-	-	-	-	-	120.00	120.00
2001	-	-	-	-	-	60.00	60.00
2002	-	-	-	-	-	110.00	110.00
2003	-	-	-	-	-	165.00	165.00
Total End 2003	1 418.89	339.20	108.94	-	1 867.03	11 294.29	13 161.32
YUKON and NWT							
Total End 1983	-	-	181.13	-	181.13	130.70	311.83
Additions 1984	-	-	-	-	-	20.00	20.00
Total End 1984	-	-	181.13	-	181.13	150.70	331.83
Additions Proposed							
1985			1.50		1.50		1.50
1988						.75	.75
Total End 1988	-	-	182.63	-	182.63	151.45	334.08

Table A6. Generation capacity by type (MW) (Cont'd)

	Steam	Gas Turbine	Internal Combustion	Nuclear	Total Thermal	Hydro	Total
CANADA							
Total End 1983	27 330.90	2 523 11	592.51	7 771.40	38 217.92	51 273.89	89 491.81
Additions 1984	544.00	75.00	4.04	1 816.00	2 439.04	3 600.76	6 039.80
Total End 1984	27 874.90	2 598.11	596.55	9 587.40	40 656.96	54 874.65	95 531.61
Additions Proposed							
1985	356.00	104.00	1.50	1 300.00	1 761.50	1 639.55	3 401.05
1986	380.00	-	-	784.00	1 164.00	91.61	1 255.61
1987	.00	-	-	784.00	784.00	26.00	810.00
1988	400.00	-	-	881.00	1 281.00	.75	1 281.75
1989	400.00	-	-	881.00	1 281.00	988.00	2 269.00
1990	380.00	-	-	-	380.00	256.00	636.00
1991	300.00	-	-	881.00	1 181.00	640.00	1 821.00
1992	750.00	-	-	881.00	1 631.00	1 017.00	2 648.00
1993	750.00	-	-	-	750.00	734.00	1 484.00
1994	-	-	-	-	-	736.17	736.17
1995	-	-	-	-	-	-	-
1996	375.00	-	-	-	375.00	846.50	1 221.50
1997	375.00	-	-	-	375.00	1 168.50	1 543.50
1998	-	-	-	-	-	151.00	151.00
1999	375.00	-	-	-	375.00	130.00	505.00
2000	750.00	-	-	-	750.00	640.00	1 390.00
2001	-	100.00	-	-	100.00	710.00	810.00
2002		200.00	-	-	200.00	110.00	310.00
2003	750.00	-	-	-	750.00	165.00	915.00
2004	-	100.00	-	-	100.00	.00	100.00
Total End 2004	34 215.90	3 102.11	598.05	15 979.40	53 895.46	64 924.73	118 820.19

Source: Energy, Mines and Resources - Utility Questionnaire

Table A7. Installed generating capacity expansion in Canada by station. Major 1984 additions and projected 1985 - 2004

Province and Station	Type*	Additions in 1984 (MW)	Year	Additions Proposed (MW)	Status	Proposed Plant Capacity (MW)
NEWFOUNDLAND						
Topsail	H	2.25			I	3.45
Lookout Brook	H	2.65			I	7.85
Cat Arm	H		1985	2 x 63.50	C	127.00
Petty Harbour	H		1985	1 x 0.30	P	
			1986	1 x 0.30	P	5.61
NOVA SCOTIA						
Annapolis Royal	H	20.0			I	20.00
Lingan	S(C)	150.0			I	
			1985	150.0	C	600.00
Fall River	H		1986	0.5	P	0.50
Nictaux	H		1986	6.8	P	6.80
New Thermal	S(C)		1991	300.0	P	300.00
QUEBEC						
La Grande -						
LG-3	H	2 x 192			I	2 304.00
Lac Robertson	H		1987	2 x 10.5	P	21.00
			1992	2 x 316.5	P	
La Grande 2	H		1993	2 x 317	P	
			1994	2 x 316.5	P	3 820.00
LG-4	H	6 x 294.5			I	
			1985	4 x 294.5	C	2 650.50
Manic 5	H		1989	4 x 247	C	2 280.00
Various Locations	H		1993	100	P	
			1994	100	P	
	IC	2.02			I	
	H	25.48			I	
ONTARIO						
Atikokan	S(C)		1985	206	C	
Bruce B	N	784	1985	784	C	
			1986	784	C	
			1987	784	C	
	GT	2 x 16.5			I	3 169.00
Darlington	N		1988	881	C	
			1989	881	C	
			1991	881	C	
			1992	881	C	
	GT		1985	4 x 26	P	3 628.00
Pickering B	N	2 x 516			I	
			1985	516	C	2 064.00

Table A7. Installed generating capacity expansion in Canada by station. Major 1984 additions and projected 1985 - 2004 (Cont'd)

Province and Station	Type*	Additions in 1984 (MW)	Year	Additions Proposed (MW)	Status	Proposed Plant Capacity (MW)
MANITOBA						
Limestone	H		1990	2 x 128	P	
			1991	5 x 128	P	
			1992	3 x 128	P	1 280.00
Wuskwatim	H		1996	87.5	P	
			1997	3 x 87.5	P	350.00
Conawapa	H		1999	130	P	
			2000	4 x 130	P	
			2001	5 x 130	P	1 300.00
SASKATCHEWAN						
Nipawin	H		1985	2 x 84	C	
			1986	84	C	252.00
Meadow Lake	GT	42				42.00
ALBERTA						
Genesee	S(C)		1988	400	C	
			1989	400	C	800.00
Keephills	S(C)	394			I	
			1993	375	P	
			1995	375	P	1 544.00
Sheerness	S(C)		1986	380	C	
			1990	380	C	760.00
Jasper	H		1987	5	P	6.40
Slave River	H		1996	2 x 153	P	-
			1996	3 x 151	P	-
			1997	6 x 151	P	-
			1998	151	P	1 816.00
New Steam	S(C)		1993	375	P	-
			1995	375	P	-
			1996	375	P	
			1997	375	P	
			1999	375	P	
			2000	2 x 375	P	
			2003	375	P	
			2005	375	P	3 375.00

Table A7. Installed generating capacity expansion in Canada by station. Major 1984 additions and projected 1985 - 2004 (Concl'd)

Province and Station	Type*	Additions in 1984 (MW)	Year	Additions Proposed (MW)	Status	Proposed Plant Capacity (MW)
BRITISH COLUMBIA						
Keenleyside	H		2000	2 x 60	P	
			2001	1 x 60	P	210.00
Murphy Creek	H		2002	2 x 55	P	
			2003	3 x 55	P	275.00
Revelstoke	H	3 x 460.75			I	
			1985	460.75	C	1 843.00
YUKON						
Whitehorse system	H	20.0			I	39.39

Legend

H	Hydro	GT	Gas Turbine
S(C)	Steam (Coal)	W	Wind
S(G)	Steam (Gas)	I	Installed
N	Nuclear	C	Under Construction
IC	Internal Combustion	P	Planned

Source: Energy, Mines and Resources - Utility Questionnaire

DEFINITIONS AND ABBREVIATIONS

Alternating Current (a-c): A current that flows alternately in one direction and then in the reverse direction. In North America the standard for alternating current is 60 complete cycles each second. Such electricity is said to have a frequency of 60 hertz. Alternating current is used universally in power systems because it can be transmitted and distributed much more economically than direct current.

Base Load: The minimum continuous load over a given period of time.

British Thermal Unit (BTu): A unit of heat. The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

Capacity: In the electric power industry, capacity has two meanings:

1. System Capacity: The maximum power capability of a system. For example, a utility system might have a rated capacity of 5000 megawatts, or might sell 50 megawatts of capacity (i.e. of power).

2. Equipment Capacity: The maximum power capability of a piece of equipment. For example, a generating unit might have a rated capacity of 50 megawatts.

Capacity Factor: For any equipment, the ratio of the average load during some time period to the rated capacity.

Cogeneration: A co-generating system produces electricity and heat in tandem. Such systems have great potential in industry, where a significant requirement for electricity is coupled with a large demand for process steam.

Current: The flow of electricity in a conductor. Current is measured in amperes.

Demand Charge: The component of a two-part price for electricity which is based on a customer's highest power demand reached in a specified period, usually a month, regardless of the quantity of energy used (e.g. $2.00 per kilowatt per month). The other component of the two-part price is the energy charge.

Direct Current (d-c): Current that flows continuously in the same direction (as opposed to alternating current). The current supplied from a battery is direct current.

Economy Energy: Energy sold by one power system to another, to effect a saving in the cost of generation when the receiving party has adequate capacity to supply the loads from its own system.

Electrical Energy: The quantity of electricity delivered over a period of time. The commonly used unit of electrical energy is the kilowatt-hour (kWh).

Electrical Power: The rate of delivery of electrical energy and the most frequently used measure of capacity. The basic unit is the kilowatt (kW).

Energy Charge: The component of a two-part price for electricity which is based on the amount of energy taken (e.g. 20 mills per kWh). The other component of the price is the demand charge.

Firm Power: Electric power intended to be available at all times during the period of the agreement for its sale.

Frequency: The number of cycles through which an alternating current passes in a second. The North American standard is 60 cycles per second, known as 60 hertz.

Gigawatt hour (GWh): A unit of bulk energy. A million kilowatt hours. A billion watt hours.

Head: The difference in elevation between the water level immediately above a hydroelectric generating station and the water level immediately below it. (Measured in feet or metres.) The power output of the station is proportional to the head.

Hertz (Hz): The unit of frequency for alternating current. Formerly called cycles per second. The standard frequency for power supply in North America is 60 HZ.

Installed Capacity: The capacity measured at the output terminals of all the generating units in a station, without deducting station service requirements.

Interruptible Energy: Energy made available under an agreement that permits curtailment or interruption of delivery at the option of the supplier.

DEFINITIONS AND ABBREVIATIONS (Cont'd)

Joule: The international unit of energy. The energy produced by a power of one watt flowing for one second. The joule is a very small unit: there are 3.6 million joules in a kilowatt hour.

Kilovolt (kV): 1000 volts.

Kilowatt (kW): The commercial unit of electric power. 1000 watts. A kilowatt can best be visualized as the total amount of power needed to light ten 100 watt light bulbs.

Kilowatt hour (kWh): The commercial unit of electric energy. 1000 watt hours. A kilowatt hour can best be visualized as the amount of electricity consumed by ten 100 watt light bulbs burning for an hour. One kilowatt hour is equal to 3.6 million joules.

Load: The amount of electric power or energy consumed by a particular customer or group of customers.

Load Factor: The ratio of the average load during a designated period to the peak or maximum load in that same period. (Usually expressed in per cent.)

Megawatt (MW): A unit of bulk power. 1000 kilowatts.

Megawatt hour (MWh): A unit of bulk energy. 1000 kilowatt hours.

Mill: 1/1000 of a dollar.

Peak Demand: The maximum power demand registered by a customer or a group of customers or a system in a stated period of time such as a month or a year. The value may be the maximum instantaneous load or more usually the average load over a designated interval of time, such as one hour, and is normally stated in kilowatts or megawatts.

Power System: All the interconnected facilities of an electrical utility. A power system includes all the generation, transmission, distribution, transformation, and protective components necessary to provide service to the customers.

Primary Energy Source: The source of primary energy from which electricity is generated. This may be falling water, uranium (by nuclear fission), coal, oil, natural gas, wind, tidal energy, etc.

Reserve Generating Capacity: The extra generating capacity required on any power system over and above the expected peak load. Such a reserve is required mainly for two reasons: first, in case of unexpected breakdown of generating equipment; second, in case the actual peak load is higher than forecast.

Voltage: The electrical force or potential that causes a current to flow in a circuit (just as pressure causes water to flow in a pipe). Voltage is measured in volts (V) or kilovolts (kV). 1 kV = 1000 volts.

Watt: The scientific unit of electric power; a rate of doing work at the rate of one joule per second. A typical light bulb is rated 25, 40, 60 or 100 watts, meaning that it consumes that amount of power when illuminated. A horse power is 746 watts.

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